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# Evaluation of the Technological Feasibility, and Cost of Selected Control Alternatives Necessary to Meet the Proposed Ohio SO2 Regulations for Industrial Boilers and Processes. Volume III. Republic Steel Corporation, Cleveland District Plant

GCA Corp, Bedford, Mass. GCA Technology Div.

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This report presents an evaluation by the GCA Corporation, GCA/Technology Division, of technological feasibility and cost of complying with the proposed Ohio sulfur dioxide regulation (40 FR 52410, November 10, 1975) at the Republic Steel Corporation's Cleveland District Plant. The Final USEPA Sulfur Dioxide Control Strategy for the State of Ohio Technical Support Documents, Vol. I and II (EPA 905/2-76-002) may be obtained from NTIS.

After collecting necessary site and process specific data by means of a plant visit, it was concluded that emissions from Boiler D would have to be reduced, and coke oven gas desulfurization would be required. The technical feasibility and cost of the Sulfiban, Holmes-Stretford, and Dravo-Stills processes for coke over gas desulfurization were evaluated. These and other control options such as using low sulfur coal were evaluated for Boiler D.

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# EVALUATION OF THE TECHNOLOGICAL FEASIBILITY, AND COST OF SELECTED CONTROL ALTERNATIVES NECESSARY TO MEET THE PROPOSED OHIO $SO_2$ REGULATIONS FOR INDUSTRIAL BOILERS AND PROCESSES

FINAL REPORT

Contract No. 68-01-3155
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September 1976

*Volume III*

REPUBLIC STEEL CORPORATION
CLEVELAND DISTRICT PLANT

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## SECTION I

## SUMMARY AND CONCLUSIONS

Republic Steel Corporation, Cleveland District Plant was visited by GCA on May 4, 1976 to collect data needed to evaluate the technical feasibility and cost of compliance with the proposed $SO_2$ emission regulations. All $SO_2$ source operations were briefly reviewed with Republic Steel representatives.

GCA concluded that emissions from boiler D would have to be reduced. Coke oven gas desulfurization would also be required. All other operations appeared to be in compliance with the proposed regulations.

Emission reductions achieved by coke oven gas (COG) desulfurization would approach 14,600 tons $SO_2$/year. The Sulfiban, Holmes-Stretford, or Dravo-Still processes could be used to clean $79 \times 10^6$ scfd of COG and would require a capital investment of $14 to $15 million. Total annual costs for these systems including cost of capital, depreciation, net operating costs and taxes would be $3.4 to $3.8 million per year. These costs would be equivalent to $0.23 to $0.26 per pound of sulfur collected.

Flue gas desulfurization or other control options to comply with the proposed regulation would reduce $SO_2$ emissions from boiler D by 840 ton/years. Capital investment for flue gas desulfurization would be $1.4 million. Total annual costs of $462,000 equivalent to $0.177/$10^6$ Btu coal burned would be required.

Incremental costs for compliance coal could not be precisely determined because Republic Steel Corporation's current costs were unavailable. However, it appears that the present incremented cost of compliance coal would be on the orders of \$0.0 to \$0.3/$10^6$ Btu.

## SECTION II

## PROCESS AND SITE DESCRIPTION

The Republic Steel Corporation Steel Plant, Cleveland District, was visited by GCA on May 4, 1976. Mr. Cliff Brown, assistant director of environmental control; Mr. Bill Tucker, air quality management engineer; Mr. Cachat, superintendent of environmental control, Cleveland district plant; and a plant engineer represented Republic Steel Corporation (RSC). Mr. Tom Blaszak and Mr. Chuck Kudla both from EPA Region V were also present at the meeting. All $SO_2$ emission sources were briefly reviewed to determine the correspondence between sources reported by RSC[1] and those listed in the technical support document[2] (TSD) and the potential compliance status of these sources if the proposed regulations are promulgated. Sources that would violate the proposed $SO_2$ emission limitations were subsequently discussed in more detail.

The RSC-Cleveland district plant is located within the Cleveland city limits, about 3 miles from Lake Erie. As shown in Figure 1 the RSC plant occupies 777 acres extending over a mile along the Cuyahoga River. Steel production capacity of this large integrated iron and steel plant is about 2,500,000 tons/year. Numerous other industrial facilities are located in the immediate vicinity along the river including steel plants operated by U.S. Steel and Jones and Laughlin and a sulfuric acid plant operated by DuPont. Hills on both sides of this shallow valley are 60 to 100 feet high.

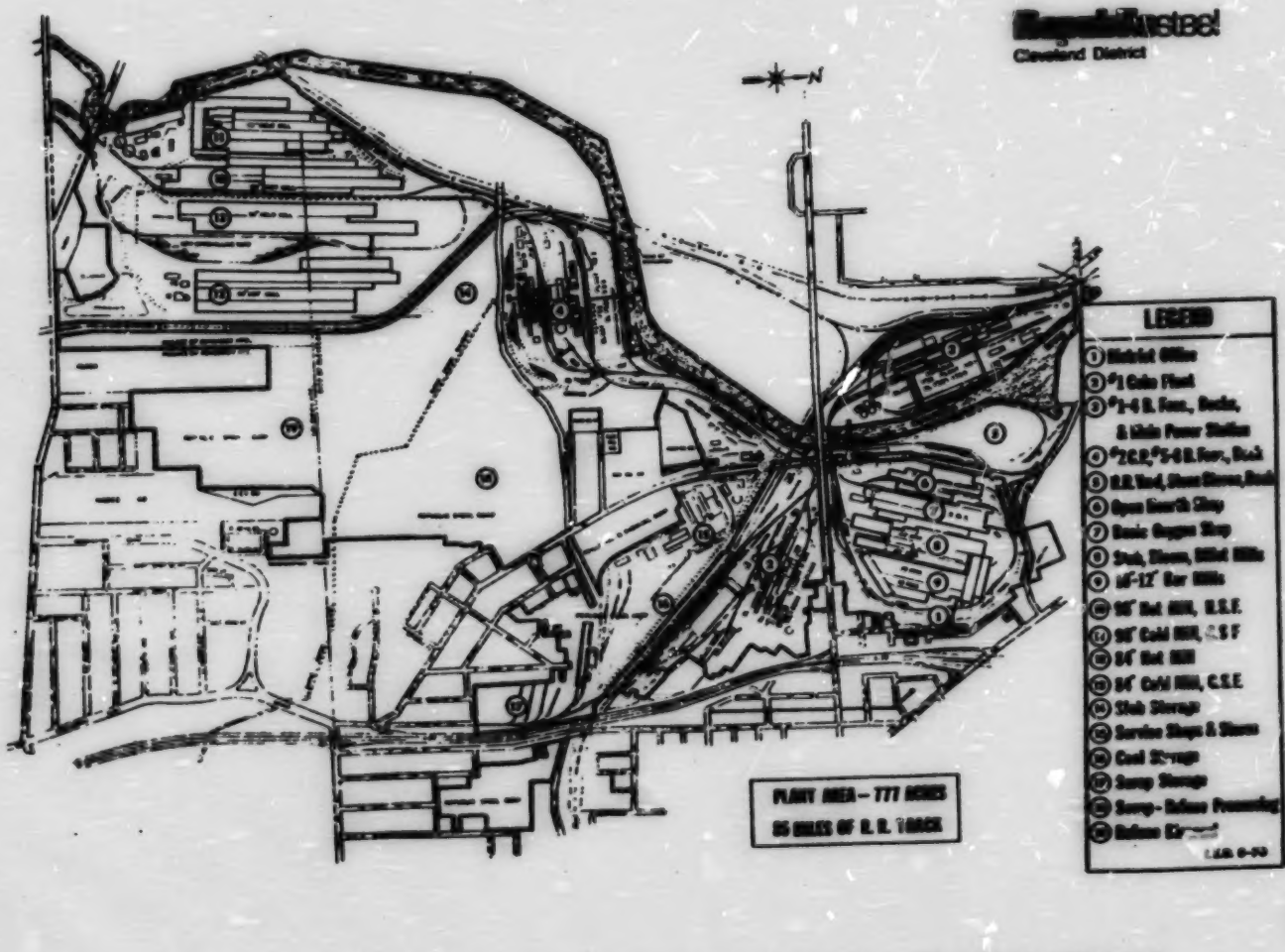


Figure 1. Republic Steel Corporation Steel Plant, Cleveland District

Table 1. REPUBLIC STEEL, CLEVELAND DISTRICT, $SO_2$ EMISSIONS FROM PROCESS SOURCES

| Ohio EPA Emission Inventory number, 13-18-00-1613- | Republic Steel source number[a] | $SO_2$ emissions, tons/year | | | Process weight,[a] tons/hr | Hours/year operation[a] | Allowable[c] emissions, tons $SO_2$/yr | Comments | Source description |
|---|---|---|---|---|---|---|---|---|---|
| | | Technical Support Document[b] | RSC-ADL 1974[a] | RSC-ADL after COGD[a] | | | | | |
| - | 1 | - | 166.4 | 20.6 | NA | 8760 | NA | d | Misc. BOF emissions |
| -P028 to P031 | 2 | - | 156.4 | 19.4 | NA | 8760 | NA | d,e | Misc. OH emissions |
| -P028 to P031 | 4-5 | - | 245.8 | 215.4 | 113.6 | 4578 | 1064 | e,f | Open hearth (OH) |
| -P013 | 6 | 450 | 241.8 | 29.9 | 48.8 | 4736 | 625 | | 10-in. bar furnace |
| -P012 | 7 | 688 | 362.8 | 44.9 | 61.2 | 4301 | 660 | | 12-in. bar furnace |
| -P021 to P027 | 8-14 | 178 | 80.6 | 10.0 | 10.4 | 8760 | 410 | g | Soaking pits 2-8 |
| -P014 to P018 | 15-19 | 441 | 302.2 | 37.4 | 47.7 | 8760 | 1138 | g | Soaking pits 11-15 |
| - | 20 | - | 9.7 | 1.2 | NA | 3285 | NA | d,h,i | Foundry |
| - | 21 | - | 49.5 | 6.1 | NA | 8760 | NA | d,i | Misc. blast furnace #1 |
| - | 22 | - | 49.5 | 6.1 | NA | 8760 | NA | d,i | Misc. blast furnace #4 |
| -P003 | 23 | 450 | 5.3 | 0.7 | 31.8 | 2112 | 209 | j | Sinter plant |
| - | 28 | - | 73.3 | 8.6 | NA | 7680 | NA | d,i | Misc. blast furnace #5 |
| - | 29 | - | 82.0 | 9.7 | NA | 8592 | NA | d,i | Misc. blast furnace #6 |
| -P037 | 32 | 860 | 951.3 | 117.8 | 46.1 | 8760 | 1112 | k | Coke battery #2 |
| -P036 | 33 | 860 | 951.3 | 117.8 | 46.1 | 8760 | 1112 | k | Coke battery #3 |
| -P035 | 34 | 860 | 951.3 | 117.8 | 46.1 | 8760 | 1112 | k | Coke battery #4 |
| -P034 | 35 | 860 | 166.4 | 20.6 | 49.7 | 8760 | 1170 | k | Coke battery #5 |

Table 1 (continued). REPUBLIC STEEL, CLEVELAND DISTRICT, $SO_2$ EMISSIONS FROM PROCESS SOURCES

| Ohio EPA Emission Inventory number, 13-18-00-1613- | Republic Steel source number[a] | $SO_2$ emissions, tons/year | | | Process weight,[a] tons/hr | Hours/year operation[a] | Allowable[c] emissions, tons $SO_2$/yr | Comments | Source description |
|---|---|---|---|---|---|---|---|---|---|
| | | Technical Support Document[b] | RSC-ADL 1974[a] | RSC-ADL after COCD[a] | | | | | |
| -P005 | 36 | 1106 | 801.5 | 94.1 | 57.8 | 8760 | 1294 | k | Coke battery #6 |
| -P004 | 37 | 1106 | 769.6 | 90.3 | 57.8 | 8760 | 1294 | k | Coke battery #7 |
| -P046 to P048 | 38-40 | 282 | 3396.0 | 672.9 | 498.6 | 4250 | 2660 | l | 84-in. slab furnace |
| -P049 to P050 | 41-42 | - | 616.8 | 72.4 | 77.4 | 8760 | 1574 | l,m | 84-in. annealing furnace |
| - | 43-46 | - | 52.8 | 6.4 | 11.6 | 4540 | 229 | l,n | J annealing furnaces |
| - | 47-50 | - | 497.6 | 58.4 | 48.4 | 8760 | 1150 | l,n | P annealing furnaces |
| - | 51-54 | - | 4.9 | 0.6 | NA | 342 | NA | l,o | Car thaw |
| - | 55-58 | - | 2.3 | 0.3 | NA | 342 | NA | l,o | Car thaw |
| -P039 to P043 | 59-63 | 1265 | 41.0 | 5.0 | 178.0 | 74 | 23.1 | p | 98-in. slab furnace |
| The following are units not specifically covered in RSC-ADL report | | | | | | | | | |
| -P019 to P020 | - | 144 | - | - | - | - | - | q | Soaking pits |
| -P001 | - | 309 | - | - | - | - | - | r | Slag pit |
| -P002 | - | 255 | - | - | - | - | - | r | Slag pit |
| -P007 | - | 473 | - | - | - | - | - | r | Slag pit |
| -P006 | - | - | - | - | - | - | - | r | Slag pit |
| -P055 | - | 127 | - | - | - | - | - | r | Slag pit |

Table 1 (continued). REPUBLIC STEEL, CLEVELAND DISTRICT, $SO_2$ EMISSIONS FROM PROCESS SOURCES

[a] Reference 1.

[b] Reference 2.

[c] GCA estimates based on the proposed regulations published in Reference 3 and the process rates reported in Reference 2. Coke oven gas, however, must be desulfurized before combustion.

[d] These are miscellaneous intermittent emissions. The source is COG burned to dry out ladles, runners, etc. and exhaust into the building. Slag pits were not included in emission estimates.

[e] Values shown here are combined for the plant, building, etc. The allowable emissions are also based on combined process weights.

[f] These four sources are open hearth furnaces. The furnaces all exhaust into a common gas main. Flow is then split and sent to two ESP's. The numbers shown are totals for all four furnaces and the allowable emissions are based on total production rate.

[g] Values shown represent each individual operation.

[h] Source was not listed in Ohio Emission Inventory.

[i] Miscellaneous BF emissions. These were not included in the Technical Support Document (TSD).

[j] This is a sinter plant. The inventory number was determined by matching stack data in the TSD and the RSC-ADL report.

[k] Allowable emissions for these sources and others have been based on process regulations. It is, of course, recognized that coke oven gas containing greater that 50 grains $H_2S$ equivalent/100 scf cannot be burned according to the proposed regulations. Emissions from source 35 are lower than the other coke ovens (sources 32-34, 36, 37) because it is fired primarily with blast furnace gas.

[l] Three 84-inch slab furnaces were considered as one process in calculation of allowable emissions.

[m] Two 84-inch annealing furnaces not included in the Technical Support Document.

[n] Annealing furnaces which exhaust into the building. Sources 43-46 are actually 12 furnaces modeled by ADL as 4 sources. Sources 47-50 are 20 furnaces modeled by ADL as 4 sources. Allowable emissions are based on the combined totals for each of the 4 sources.

Table 1 (continued). REPUBLIC STEEL, CLEVELAND DISTRICT, $SO_2$ EMISSIONS FROM PROCESS SOURCES

[o]This is gas burned to thaw out cars. No stacks exist.

[p]These five 98-inch slab furnaces have been shut down.

[q]These two soaking pits are no longer used. They are, in fact, unusable.

[r]These are blast furnace (BF) slag pits reported in the TSD but not reported in the RSC-ADL report. However, other miscellaneous emissions associated with the blast furnaces are reported as sources 21, 22, 28, 29. Source -P055 could not be found in the RSC-ADL report or in the Emission Inventory.

A summary of process sources producing $SO_2$ emissions is presented in Table 1. The first column presents the Ohio Emission Inventory number and the number used in the technical support document while the second column presents the source number assigned by Republic Steel. These documents present further details on the individual sources. The majority of the emissions listed in Table 1 result from combustion of coke oven gas (COG). All the process sources appear to easily comply with the proposed regulation S52.1881(b)(8).[3] However, COG must be desulfurized to less than 50 grains $H_2S$ equivalent/100 scf limit according to regulation S52.1881(b)(12), thus reducing emissions from most process sources. The primary objective in compiling Table 1 was to determine the potential compliance status and to identify emission sources. Emission estimates from the technical support document[1] and RSC[2] show many differences and those listed in the Ohio Emission Inventory show further differences. Minor differences appear to be due to changes in fuel use. Definitive reasons for other differences were not determined. Total $SO_2$ emissions from process sources according to the TSD were 13,500 tons, which is close to the RSC-ADL estimate of 12,000 tons.* It appears that RSC did not include $SO_2$ emissions from the slag pits. Desulfurization of COG would be the only process change required under the proposed regulation. Therefore, other processes are not discussed further in this report.

$SO_2$ emissions from boilers, fossil fuel-fired steam generators, were also investigated. The eight boilers operated by RSC at the Cleveland District Plant are listed in Table 2. Under the proposed regulation fossil fuels include fuels derived from fossil fuels such as blast furnace gas and COG. Boilers at RSC are fired with blast furnace gas, natural gas, residual oil, COG and coal. COG and blast furnace gas are the primary fuels.

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*RSC indicated in a later letter dated August 13, 1976 to EPA, Region V that the ADL report has been revised and now indicates $SO_2$ emissions of 15,200 tons/year for the above sources.[7]

## Table 2. REPUBLIC STEEL, CLEVELAND DISTRICT, $SO_2$ EMISSIONS FROM BOILERS

| Ohio EPA Emission Inventory number, 13-18-00-1613- | Republic Steel source number[a] | $SO_2$ emissions | | | | | Rated capacity,[a] $10^6$ Btu/hr | Allowable emissions,[c] lb $SO_2/10^6$ Btu | Comments | Boiler identification |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Technical Support Document,[b] tons/year | RSC-ADL 1974[a] | | RSC-ADL after COGD[a] | | | | | |
| | | | tons/yr | lb/$10^6$ Btu | tons/yr | lb/$10^6$ Btu | | | | |
| -8009 | 3 | 2003 | 473.4 | 0.56 | 429.0 | 0.51 | 450 | 2.24 | | #234 |
| -8001 | 24 | 876 | 523.7 | 0.39 | 178.4 | 0.13 | 336 | 2.46 | | A |
| -8002 | 25 | 876 | 480.3 | 0.40 | 164.1 | 0.14 | 336 | 2.46 | | B |
| -8003 | 26 | 876 | 505.7 | 0.40 | 172.2 | 0.14 | 336 | 2.46 | | C |
| -8004 | 27 | 745 | 3826.7 | 2.88 | 3729.1 | 2.80 | 461 | 2.22 | d | D |
| -8005 to 8006 | 30 | 94 | 472.0 | 0.38 | 55.4 | 0.04 | 460 | 2.22 | e | 1 and 2 |
| -8007 | 31 | 2048 | 1008.5 | 0.86 | 691.2 | 0.59 | 335 | 2.47 | f | 3 |

[a]Reference 1.

[b]Reference 2.

[c]GCA estimates based on the proposed regulations published in Reference 3 and the boiler capacities reported in Reference 2 and reviewed during the site visit. Coke oven gas, however, must be desulfurized before combustion.

[d]A misprint in Reference 1 indicated emissions of 826.7 tons/yr instead of 3826.7 tons/yr obtained by summing emissions by fuel. Coal is the primary fuel for this boiler. Data subsequently submitted by RSC to GCA indicates that 3.5 percent sulfur coal was burned in 1974. On this basis, 1974 $SO_2$ emissions were calculated to be 7500 tons which would exceed the proposed regulation.

[e]Both boilers vent to a common stack. Reported data represent the sum of both boilers.

[f]This boiler burns coal only intermittently deriving less than 20 percent of the yearly heat input from coal in 1974. As a yearly average, this boiler would comply with the proposed regulations. However, most of the coal is burned during casting which occurs every 4 hours and lasts 30 minutes. GCA's estimate is that this boiler will be in compliance.

Coal is the primary fuel only in boiler D. Differences in $SO_2$ emission estimates from the technical support document and RSC may be attributable to year-to-year variations in fuel consumption and composition. In the Ohio Emission Inventory, much larger quantities of coal were reported to be used in the boilers but RSC reduced their coal consumption in late 1973. $SO_2$ emissions from coal reported in the Ohio Emission Inventory also appear to be incorrectly calculated. Data supplied to GCA by RSC for the year 1974 show that the coal burned in boiler D averaged 3.5 percent sulfur, indicating emissions of 7500 tons $SO_2$ - not 3826 tons. Currently boiler D is burning coal with a sulfur content of 1.5 to 2.3 percent with most analyses showing about 2 percent sulfur. For 2 percent sulfur the boiler D emissions would be 3800 ton $SO_2$/yr which would not comply with the proposed regulation; a reduction of 19 percent in $SO_2$ emissions would be required.

BY-PRODUCT COKE OVENS

Two by-product coke plants separated by about 2000 ft. are operated at the Republic Steel Corporation Cleveland District Plant, as previously shown in Figure 1. Both plants currently use 0.9 percent sulfur coal. The No. 1 plant containing 228 coke ovens consists of batteries 2 and 3 built in 1958, 4 built in 1957 and 5 built in 1943. No. 5 battery is scheduled to be phased out in late 1976 and replaced by the new No. 1 battery to maintain coke production capacity. Coal feed to the No. 1 plant averaged 4400 tons coal/day producing about 3100 tons of coke/day in 1974 and RSC reports this as the capacity. Coke oven gas production is about $46 \times 10^6$ scfd[7] or 10,450 scf/ton of coal feed. The smaller No. 2 plant consists of 126 ovens. Maximum coal use is 3150 tons/day producing 2145 tons coke/day and an average of $33 \times 10^6$ scfd COG. RSC reports that on a yearly basis coal feed capacity is 2770 tons/day.

Based on the normal COG $H_2S$ content (reported by RSC in requests for COG desulfurization system cost estimates) of 461 gr/100 scf and 381 gr/100 scf for the No. 1 and No. 2 plants, respectively, $SO_2$ emissions from COG

combustion throughout the Cleveland works would be 16,600 tons/year.* Emissions for a full year would, of course, vary depending on downtime required for maintenance and actual coke production requirements which are determined by the market for steel. Arthur D. Little, on behalf of RSC, estimated 1974 $SO_2$ emissions from COG combustion to be 14,376 tons[1] which indicates production was below capacity. The proposed COG regulation would reduce $SO_2$ emissions to 1940 tons/year.

Before combustion the COG is processed through typical by-product recovery plants, one at each coke plant. Exhaust fans are used to maintain a relatively fixed suction pressure and maintain the gas flow through the by-product plant. Most of the tars are removed in the primary coolers. An electrostatic precipitator follows and removes the remaining tar particles. After essentially all the tar has been removed, the gas is reheated and ammonia sulfate is produced in ammonia saturators. COG leaving the ammonia saturators is cooled again and finally benzol wash oil scrubbers are employed to remove naphthalene and similar organics. At this point, to comply with the proposed regulation the COG will be routed to the desulfurization plant before it will be put back into the normal gas distribution system. Typical product yields for by-product coking are presented in Table 3.

Table 3. TYPICAL YIELDS OF COKE PLANT PRODUCTS PER TON OF COAL[4]

| | |
|---|---|
| Blast furnace coke and coke breeze | 1,400 lb |
| Coke oven gas | 10,500 scf |
| Tar | 10 gal |
| Ammonium sulfate | 25 lb |
| Waste ammonia liquor | 25 gal |
| Light oil | 3 gal |

*These $H_2S$ concentrations were included in RSC request for estimates from equipment vendors for COG desulfurization systems. Later data submitted by RSC indicated $H_2S$ concentrations of 426 and 404 gr/100 scf during 1974. Based on the gas flows of $46 \times 10^6$ scfd and $33 \times 10^6$ scfd, $SO_2$ emissions would be 16,200 tons/yr.

COG consumption throughout the Cleveland District Plant is qualitatively illustrated in Tables 1 and 2 by the emission reduction that would be achieved at each emission point by COG desulfurization. RSC reports that 27 percent of the COG is used to underfire No. 1 coke plant, 7 percent to underfire No. 2 coke plant, 20 percent in the primary mill area, 20 percent in the mid-plant area and 27 percent in the steel mill complex.[1] The 34 percent of total COG used to underfire the ovens is slightly lower than other facilities using 40 percent but RSC also uses blast furnace gas for underfiring.

The sulfur in COG originates in the coal charged to the ovens which currently contains 0.9 percent sulfur but may increase to 1.1 to 1.2 percent by 1980.[1] Total sulfur content of the COG based on COG analyses of 461 gr $H_2S$/100 scf for the No. 1 battery and 381 gr $H_2S$/100 scf for the No. 2 battery, the gas flow rates, and coal feed reported by RSC represents 53 percent of the original coal sulfur content which is the same as data reported in AP-42.[5*]

The proposed Regulation S54.1881(b)(12) for the State of Ohio would require a large reduction in the sulfur content of COG. The regulation states the following:

> No owner of operator of a by-product coke oven shall cause or permit the combustion of by-product coke oven gas containing a total sulfur content expressed as hydrogen sulfide ($H_2S$) in excess of 50 grains $H_2S$ per dry standard 100 cubic feet of coke oven gas. Included in the permitted concentration of $H_2S$ are emissions of sulfur dioxide emitted as off gas from the sulfur recovery system operated in conjunction with the sulfur removal equipment, and sulfur dioxide emitted due to the mixing, flaring, or distribution of by-product coke oven gas.

Thus for a plant which burns 79 million scf of coke oven gas per day, total sulfur emissions expressed as $H_2S$ must not exceed 5,642 lb/day.

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*The same conclusion applies if COG analyses of 426 gr H2S/100 scf and 404 gr $H_2S$/100 scf as recently reported by Republic Steel for 1974 are used.

An 88 percent reduction from current emission levels attributable to COG combustion at the RSC-Cleveland works will be required. Coke oven gas desulfurization and sulfur recovery will be required to achieve this emission reduction. More effective COG desulfurization permits less efficient sulfur recovery plants. As illustrated in Figure 2, if the coke oven gas from Plant No. 1 is desulfurized from 461 gr $H_2S$/100 scf to 40 gr $H_2S$/100 scf* corresponding to an $H_2S$ absorption efficiency of 91.3 percent, then a sulfur recovery efficiency of 97.6 percent is required. However, if the COG is desulfurized to 10 gr $H_2S$/100 scf,* (97.8 percent absorption) a sulfur recovery efficiency of only 90.3 percent is required. Lower efficiencies are acceptable for the No. 2 coke plant as shown in Figure 2. The relative cost of high efficiency sulfur recovery versus high efficiency COG desulfurization will vary with the control system and, therefore, the optimum absorption and recovery efficiency will vary.

Republic Steel Corporation contacted Black, Sivalls and Bryson; Wilputte; Dravo; and Koppers several times over the past couple of years to obtain cost estimates for COG desulfurization. The design basis and the cost estimates submitted in December 1975 by the equipment manufacturers were recently forwarded to GCA and reviewed by GCA. Important design conditions used by the equipment vendors are listed in Table 4. Republic Steel prefers a completely separate system for each coke plant so that a failure of the sulfur or sulfuric acid recovery facility would only affect one coke plant. However, central sulfur recovery might reduce the cost of COG desulfurization. The gas flow rate for coke plant No. 1 as listed in Table 4 appears to be based on the operation of all five coke batteries but RSC now plans to operate only four batteries; i.e., the new battery will replace one of the older batteries. The normal gas flow is therefore $1.925 \times 10^6$ scf/hr not $2.70 \times 10^6$ scf/hr. GCA adjusted the cost estimates as required to the lower flow rate. Recent estimates[7] of a lower $H_2S$ concentrations in the COG from the No. 1 plant and a higher concentration from the No. 2 plant

*Total sulfur content expressed as $H_2S$.

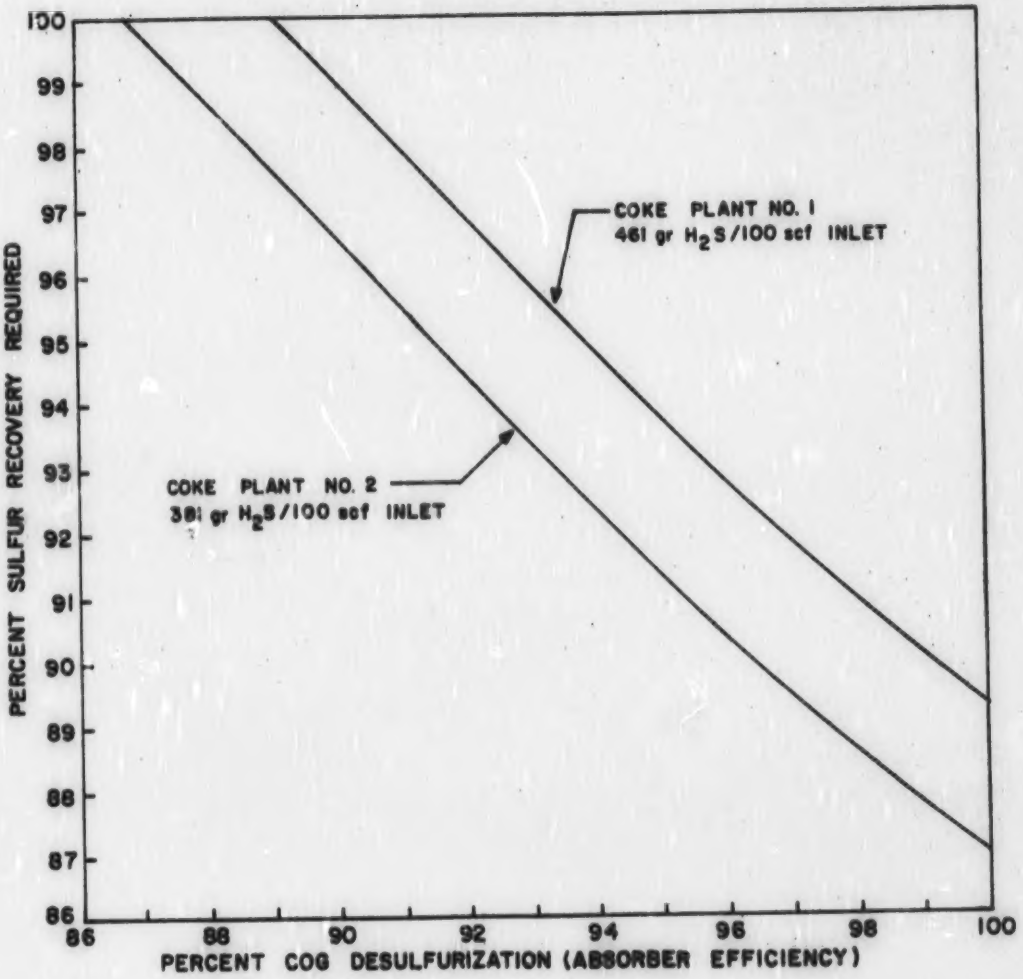


Figure 2. COG desulfurization and sulfur recovery plant efficiencies required to meet the proposed 50 gr $H_2S$ equivalent/100 scf standard at Republic Steel Corporation Cleveland works

would have a minor impact on costs and were not considered. Variations in $H_2S$ concentration can be expected to occur on a monthly and yearly basis.

Table 4. PRIMARY DESIGN DATA USED BY EQUIPMENT VENDORS TO ESTIMATE COG DESULFURIZATION CAPITAL COSTS AT REPUBLIC STEEL, CLEVELAND DISTRICT

| | No. 1 coke plant | No. 2 coke plant |
|---|---|---|
| Gas Flow | | |
| Maximum, $10^6$ scf/hr | 2.98 | 1.50 |
| Average, $10^6$ scf/hr | 2.70 | 1.37 |
| Present Max. $H_2S$, gr/100 scf | 461 | 381 |
| Present Max. HCN, gr/100 scf | 39 | 21.3 |
| Other gases, mole percent | | |
| $CO_2$ | 2.80 | 2.40 |
| $O_2$ | 0.40 | 0.40 |
| CO | 7.00 | 6.20 |
| $H_2$ | 51.40 | 53.90 |
| $CH_4$ | 32.70 | 32.70 |
| Maximum Desulfurization System Pressure Drop, in water | 10 | 10 |

Boiler D

Boiler D (source No. 26, ID B004) is one of two boilers at Republic Steel's Cleveland District Plant presently firing coal and the only one projected to exceed the proposed $SO_2$ emission limitations. Seven of the eight boilers presently in use were originally designed to burn coal, coke oven gas, blast furnace gas, natural gas, and oil, as well as mixtures of these. However, in late 1973, coal firing was discontinued in all boilers except boilers D and 3. Boiler 3 (source No. 31, ID B007) burned 19 percent coal, 60 percent blast furnace gas, 14 percent COG, and 7 percent natural gas and would comply with the proposed regulations. On the other hand boiler D burns 80 to 95 percent coal and would be required to reduce $SO_2$ emissions.

Boiler D is part of the Main Power Station, located near blast furnaces 1 to 4 (see Figure 1). About 10 percent of the energy output is converted to electricity while the remainder is split evenly between process and space heat. It is a relatively new dry bottom boiler, installed in 1967, and designed primarily to burn coal. However, varying amounts of COG, blast furnace gas, and natural gas comprising 5 to 20 percent of the total fuel input are also burned. Rated capacity is 461 x $10^6$ Btu/hr and normal capacity is 400 x $10^6$ Btu/hr. RSC estimates that the remaining boiler life is only 14 years, indicating a total life of 23 years which appears to be low. Particulate control equipment presently consists of a multiple cyclone but a new electrostatic precipitator is under construction and is scheduled to begin operation in June 1976. Particulate emissions will be less than 0.1 lb/$10^6$ Btu, equivalent to about 0.06 gr/scf. Flue gases exit through a 225 foot stack with an inside diameter of 10.75 feet. Additional boiler design and operating data are presented in Table 5.

The applicable regulation for boilers in Cuyahoga County S52.1881(b)(3) iii states:

> "For fossil-fuel fired steam generating units between 22.5 and 3000 x $10^6$ Btu/hour total rated capacity of heat input, the emission rate in lbs. $SO_2/10^6$ Btu actual heat input shall be calculated by the following equation:
>
> $$E = 16.71\ Qm^{-0.329}$$
>
> where Qm is the total rated capacity of heat input in $10^6$ Btu/hour and E is the allowable emission rate in lbs. $SO_2/10^6$ Btu actual head input."

Because the rated heat input capacity is 461 x $10^6$ Btu/hr, the emission limit for boiler D is 2.22 lb $SO_2/10^6$ Btu. In 1974, boiler D was operated for 8014 hours at an average heat input of 331 x $10^6$ Btu/hr and an average emission rate of about 5.6 lb $SO_2/10^6$ Btu. However, 1974 was not typical of normal operations, as blast furnace gas was unavailable due to a blast

Table 5. BOILER D DESIGN AND OPERATING DATA

| Type | Pulverized coal, dry bottom[a] |
|---|---|
| Rated capacity, $10^6$ Btu/hr | 461 |
| Normal operating rate, $10^6$ Btu/hr | 400 |
| Annual load factor,[a] percent | 80 |
| Flue gas flow at rated capacity, scfm | 95,000 |
| Flue gas flow at normal operating rate, scfm | 82,000 |
| Flue gas temperature, $^oF$ | 520 |
| Excess air, percent | 10-20 |
| Coal consumption,[b] tons/year | 110,000 |
| Coal heat content, Btu/lb | 11,500 |
| Coal sulfur content, percent | 2 |
| $SO_2$ concentration in stack gas, ppm | 1300-1400 |
| $SO_2$ emission rate, lb/$10^6$ Btu | |
| Coal combustion only | 3.32 |
| Normal operation | 2.74 |
| After COG desulfurization | 2.67 |
| Allowable $SO_2$ emission rate, lb/$10^6$ Btu | 2.22 |
| Emission reduction required, percent | 19-33[c] |
| Flue gas flow treated,[d] scfm | 20,000-35,000[c] |

[a] 8014 hours/year at an average 400 x $10^6$ Btu/hr.

[b] Normal fuel mix is 81 percent coal, 15 percent blast furnace gas, and 3.4 percent COG. During 1974, 95 percent of the fuel was coal, 5 percent COG, and 0 percent blast furnace gas due to a blast furnace shutdown.

[c] If coal only was burned.

[d] Based on 90 percent $SO_2$ collection efficiency to achieved the required emission reduction.

furnace shutdown and a higher sulfur coal was used. The normal average operating rate is 400 x $10^6$ Btu/hr with a fuel mix of 81 percent coal, 15 percent blast furnace gas and 3.4 percent COG. Based on the present typical coal sulfur content of 2 percent, and the heating value of 11,500 Btu/lb the normal emission rate would be 2.74 lb $SO_2/10^6$ Btu or about 4430 tons/$SO_2$ year. To meet the regulation a small emission reduction of only 19 percent would be needed from normal operating conditions. The largest potential emission reduction required would be 33 percent from an emission rate of 3.32 lb $SO_2/10^6$ Btu that would occur if only coal were burned. This latter situation would only be approached during unusual years when a blast furnace is shut down as during 1974.

## SECTION III

## $SO_2$ CONTROL METHODS

GCA's review of Republic Steel Corporation, Cleveland Plant operations and the proposed regulations indicates that COG produced by two by-product coke plants would require desulfurization and $SO_2$ emissions from boiler D would need to be reduced. Preliminary analysis shows that the cost of controlling the coke plant emissions would be almost one order of magnitude greater than the cost for controlling $SO_2$ emissions from boiler D.

### CONTROL TECHNOLOGY FOR COKE OVEN GAS DESULFURIZATION

The Vacuum Carbonate, Sulfiban, Firma Carl Still, and Stretford processes are commercially available in the United States and are currently operating on North American coke ovens. In addition, the Diamox process is reported to be available.[6] These processes are technically capable of achieving the proposed sulfur emission limitation of 50 grains $H_2S$ equivalent/100 scf. A few of the systems may be able to achieve 10 grains $H_2S$/100 scf.

Coke oven gas desulfurization units are operating at nine United States plants, under construction at two plants and committed to construction at two plants as illustrated in Table 6. These 13 plants represent a reasonably large fraction of the 62 United States coke oven plants.[8] Comparison of the clean coke oven gas production capacity of 417,000 $10^6$ scf/year in Table 6 to the 1973 industry wide production of 995,000 x $10^6$

Table 6. INVENTORY OF U.S. COKE OVEN GAS DESULFURIZATION PLANTS, MAY 1976[a]

| Plants in operation[b] | Location | Gas production $10^6$ scf/day | Process |
|---|---|---|---|
| Bethlehem Steel Co. | Burns Harbor, Ind. | 120 | Vacuum carbonate |
| | Lackawanna, N.Y. | 50 | Vacuum carbonate[c] |
| | Sparrows Point, Md. | 100 | Vacuum carbonate[c] |
| | Bethlehem, Pa. | 100 | Sulfiban |
| Donner Hanna Coke Co. | Buffalo, N.Y. | 30 | Vacuum carbonate |
| National Steel Co. | Weirton, W.Va. | 70 | Vacuum carbonate |
| United States Steel Co. | Clairton, Pa. | 300 | Vacuum carbonate |
| Inland Steel Co. | Indiana Harbor, Ind. | 50 | Vacuum carbonate |
| Shenango, Inc. | Pittsburgh, Pa. | 32 | Sulfiban |
| Under construction | | | |
| Armco Steel Co. | Middletown, Ohio | 60 | Firma Carl Still |
| Jones and Laughlin | Pittsburgh, Pa. | 80 | Sulfiban |
| Commitments for construction | | | |
| Bethlehem Steel Co. | Franklin, Pa. | 60 | Sulfiban |
| Wheeling-Pittsburgh Steel | Follansbee, W.Va. | 90 | Firma Carl Still |

[a] References 9, 10, 11, 12.

[b] Dominion Foundry and Steel Ltd., Hamilton, Ontario, Canada operates a 42 x $10^6$ scf/day Stretford system.

[c] These systems are being replaced by larger Sulfiban systems.

indicates that up to 40 percent of coke oven gas is currently cleaned. This is a good indication that coke oven gas desulfurization is technically and economically feasible. At this time the Vaccum Carbonate, Sulfiban, Firma Carl Still and Stretford process have the most operating experience in North America. The six most recent systems listed in Table 6 are four Sulfiban systems and two Firma Carl Still systems.

## LIQUID ABSORPTION PROCESS

The four liquid absorption processes, Vacuum Carbonate, Sulfiban, Firma Carl Still and Diamox involve similar unit operations. Raw COG is cleaned by absorption of acid gases in $Na_2CO_3$, monoethanolamine, ammonia, and ammonia, respectively. Steam is then used to strip the acid gas from the absorbing medium, thus regenerating the absorbent. Particularly in the Vacuum Carbonate system, higher $H_2S$ collection efficiencies require large increases in steam consumption to regenerate a clean absorbent. Claus plants have generally been used for sulfur recovery but a couple of newer systems use or will use sulfuric acid plants. HCN must be destroyed before the sulfur rich gases enter the recovery plant to prevent corrosion and plugging problems.

### Vacuum Carbonate Process

As shown in Table 6, the Vacuum Carbonate process is the most widely used COG desulfurization method. Currently this process is employed at seven plants to clean $710 \times 10^6$ scf/day of raw COG. The Vacuum Carbonate process has been marketed by Koppers* since the mid 1950's. $Na_2CO_3$ is used in this liquid absorption system to collect acid gases. Originally the process was designed to achieve 50 grains $H_2S$/100 scf (90 percent absorption of a 500 grains $H_2S$/100 scf raw gas) but recent modifications are reported to provide higher efficiencies.[13] Bethlehem Steel Corporation

*Koppers Company, Inc. Pittsburgh, Pennsylvania 15219

used the system before emission controls were required to partially clean the COG for metallurgical purposes.

Acid gases collected by the $Na_2CO_3$ solution are stripped under a slight vacuum and transferred to the sulfur recovery unit. As discussed in the previous section, a 500 grains $H_2S$/100 scf raw gas must be desulfurized to below 50 grains $H_2S$/100 scf or a 100 percent efficient sulfur recovery unit would be needed. Since 1972 and 1973, Koppers has offered a system capable of 93 percent absorption but at substantially increased steam and utility costs.[13] An example process flow sheet of the above process is presented in Figure 3. A two stage system, tested on a pilot scale, is also available that includes design modifications and that reportedly can achieve 10 grains $H_2S$/100 scf.[13,14] These vacuum carbonate systems do not remove organic sulfur compounds which may be present in the 5 to 25 gr ($H_2S$ equivalent)/ 100 scf range.

HCN has caused Claus plant operating problems. This is common to all COG desulfurization systems and solutions to this problem are discussed later. Two liquid waste streams result from operation of the vacuum carbonate process. Absorbing solution is normally recycled but based on operating experiences must be replaced every 8 to 36 months.[9] Condensates from the ejector jets containing dissolved $H_2S$, HCN, etc., are also a potential liquid waste problem. These acid gases may be stripped from the condensate and returned to the raw COG.

Sulfiban Process

The Sulfiban process, developed by Bethlehem Steel Corporation and Black, Sivalls and Bryson* and marketed by the latter organization, is being utilized at two plants and four units are under construction at other

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Industrial Products Division
P.O. Box 27125
Houston, Texas 77024

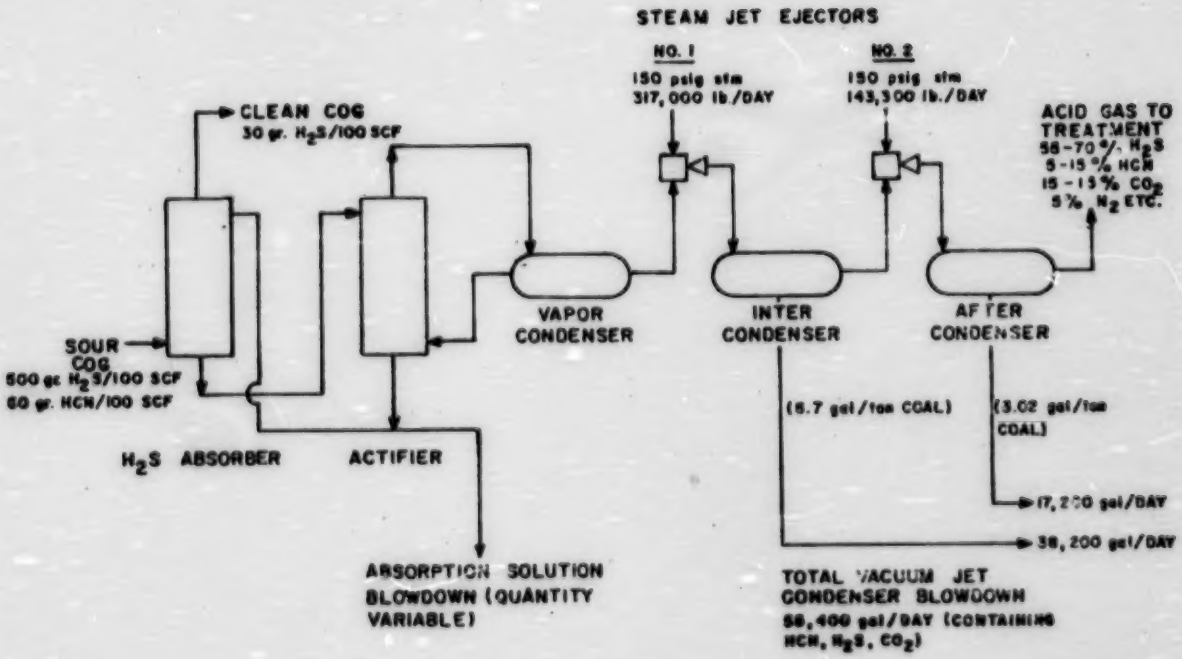


Figure 3. Process flowsheet: Vacuum Carbonate process based on 60 million scf/day COG and 93 percent sulfur collection efficiency[9]

plants. This is a relatively new process with full scale units in operation for less than 3 years. An alkanolamine solution (13 to 18 percent monoethanolamine) is used as an absorbent in this liquid absorption process. Sulfiban pilot units have demonstrated a clear capability to clean COG to 10 grains $H_2S$/100 scf or less.[9] Commercial operation has substantiated the pilot plant results. The Shenango plant has operated at absorption efficiencies in the high 90 percent range.[15] The Bethlehem Pennsylvania plant, designed to process 100 million scf/day of raw COG containing 325 to 375 gr $H_2S$/100 scf, has sweetened COG to a 4 to 6 gr $H_2S$(total sulfur equivalent)/100 scf level.[16] Figure 4 is a flow diagram of the Sulfiban system operating at Bethlehem including a four-reactor Claus sulfur recovery unit.

The degree of desulfurization is dependent upon the monoethanolamine (MEA) solution circulation rate, the temperature of the solution, and the reboiler steam rate.[16] Table 7 indicates the degree of desulfurization as a function of MEA circulation rate. Higher desulfurization levels increase the steam requirement for regenerating the amine solution. The steam requirement for desulfurizing to a 10 gr $H_2S$/100 scf level is approximately double that required for a 50 gr $H_2S$/100 scf level.[9]

Table 7. COKE OVEN GAS DESULFURIZATION AS A FUNCTION OF AMINE CIRCULATION RATE[16]

COG Flow: 56 x $10^6$ scfd
Contactor Inlet Temperature: 75 to 80°F
Raw COG Loading: 325-375 gr $H_2S$/100 scf
3 to 8 gr organic sulfur ($H_2S$ equivalent)/100 scf

| Amine circulation rate, gpm | Sweetened COG loading, gr $H_2S$/100 scf | Acid gas composition | |
|---|---|---|---|
| | | % $H_2S$ | % $CO_2$ |
| 400 | 4-6 | 43.6 | 52.6 |
| 350 | 5-15 | -- | -- |
| 300 | 15-20 | 44.0 | 52.0 |
| 280 | 20-25 | -- | -- |
| 250 | 25-30 | 44.4 | 51.2 |
| 200 | 30-40 | -- | -- |

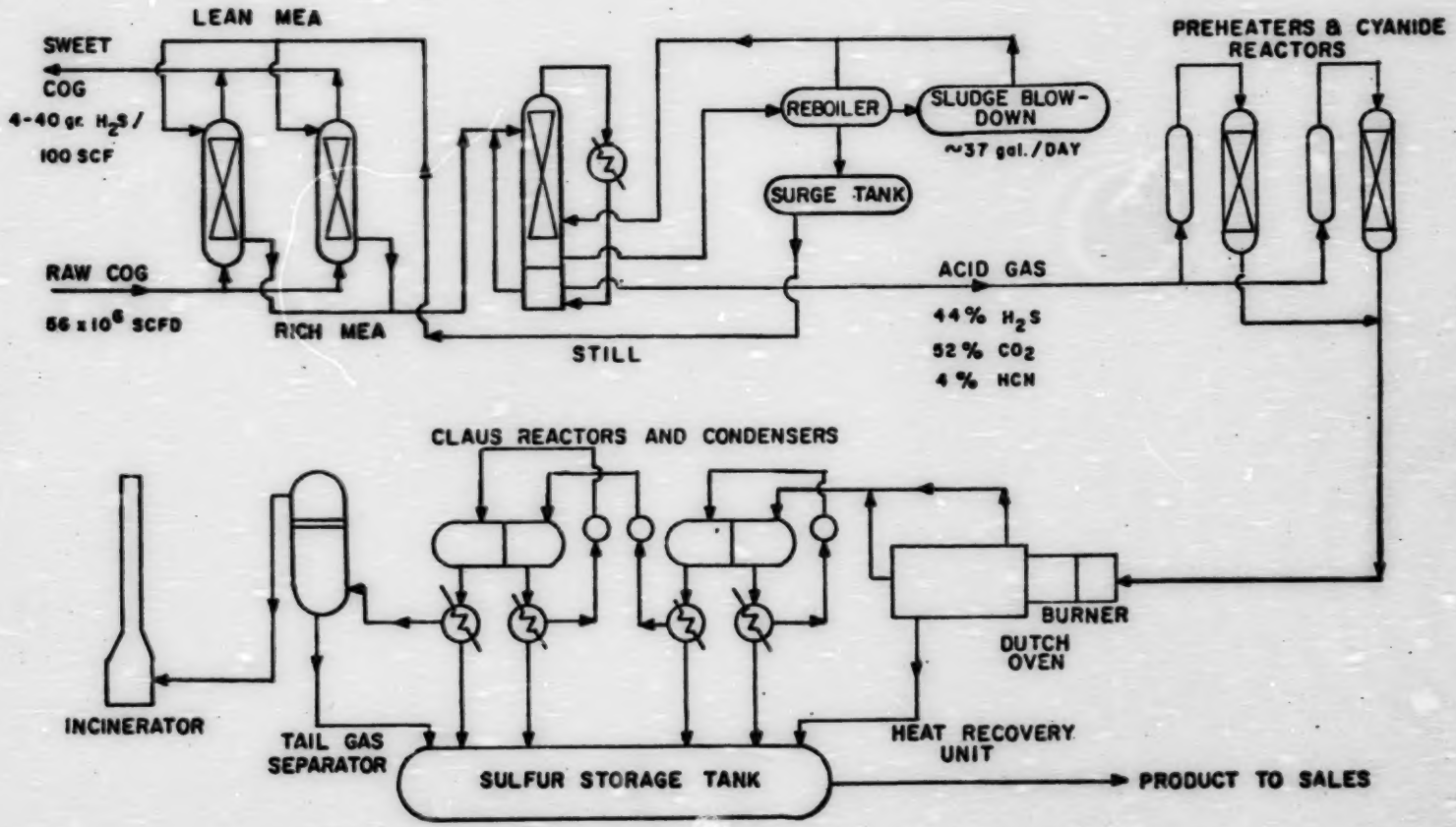


Figure 4. Process flowsheet: Sulfiban process including Claus plant sulfur recovery[16]

An advantage of amine desulfurization utilized in the Sulfiban process is the simultaneous removal of organic sulfur. This can be important since the proposed emission regulation limits total sulfur content expressed as $H_2S$ equivalent. Typical organic sulfur content of raw COG at the Bethlehem plant range from 3 to 8 gr ($H_2S$ equivalent)/100 scf or less.[16] However, at other facilities raw COG may contain as much as 25 gr organic sulfur ($H_2S$ equivalent)/100 scf. The Sulfiban process is the only liquid absorption process which removes organic sulfides from the COG stream.

The amine absorption system also has an inherent but minor disadvantage when compared to sodium carbonate absorption. The MEA solution absorbs more $CO_2$, thus producing an acid gas containing a substantially higher $CO_2$ concentration. The result is higher production of organic sulfur compounds in the Claus plant combustor. However, these compounds can be efficiently converted to elemental sulfur by modification of the first catalytic converter and switching to a more active catalyst. The cost increase is minor and is included in this report.

As the MEA solution cycles through the system, small quantities of thermally stable compounds such as ferrocyanide and formamide are formed. To prevent the build-up of these compounds, a purge stream is sent to a reclaimer where the MEA is recovered by distillation and the residue is discarded.[16] This sludge contains FeS, prussian blue, thiourea, etc. Approximately one barrel per day of sludge is produced from a plant processing 60 million scf/day of COG. Mixing the sludge with sinter plant feed is one disposal method which has been utilized successfully.[9]

As with the Vacuum Carbonate system, an HCN treatment facility is necessary to prevent Claus plant operating difficulties. This facility will be discussed in a later section.

## Firma Carl Still Process

Firma Carl Still has developed this COG desulfurization system to a high degree of sophistication in Germany.[13] Dravo Corporation* is currently marketing this system in the United States as the Dravo-Still process. The first United States system is expected to start up in mid-1976 at Armco Steel Co., in Middletown, Ohio.[11] A commitment for construction has been made by Wheeling-Pittsburgh Steel for a $90 \times 10^6$ scf/day plant.[10] The Dravo-Still system is an ammonia based liquid absorption process capable of cleaning COG to 10 grains $H_2S$/100 scf but it does not collect organic sulfur. A process flow diagram for a typical Dravo-Still system is presented in Figure 5.

Desulfurization capability increases with increasing $NH_3$ concentration. Ammonia based absorption systems are also sensitive to temperature with effectiveness decreasing as temperature increases. This appears to be the reason why a precooler is needed, and 60 to 70°F cooling water is required. At some plants a chiller will be needed during the summer to meet the cooling water criteria. The Dravo-Still system is capable of collecting high percentages of $H_2S$ but total desulfurization is limited by organic sulfur compounds (usually 5 to 10 grains/100 scf but as high as 25 gr/100 scf) which are not absorbed.

Dravo proposes to eliminate Claus plant tail gas by a catalytic reduction furnace. Unconverted $SO_2$ and $H_2S$ in the tail gas pass to the catalytic furnace where a small amount of coke oven gas is burned with a deficiency of air. This reduces all sulfur compounds back to $H_2S$. The resulting gas is cooled and recycled back to the $H_2S$ absorber. This recycle lowers the heating value of the COG by 10 to 12 Btu/scf but eliminates all gaseous discharge to the atmosphere.

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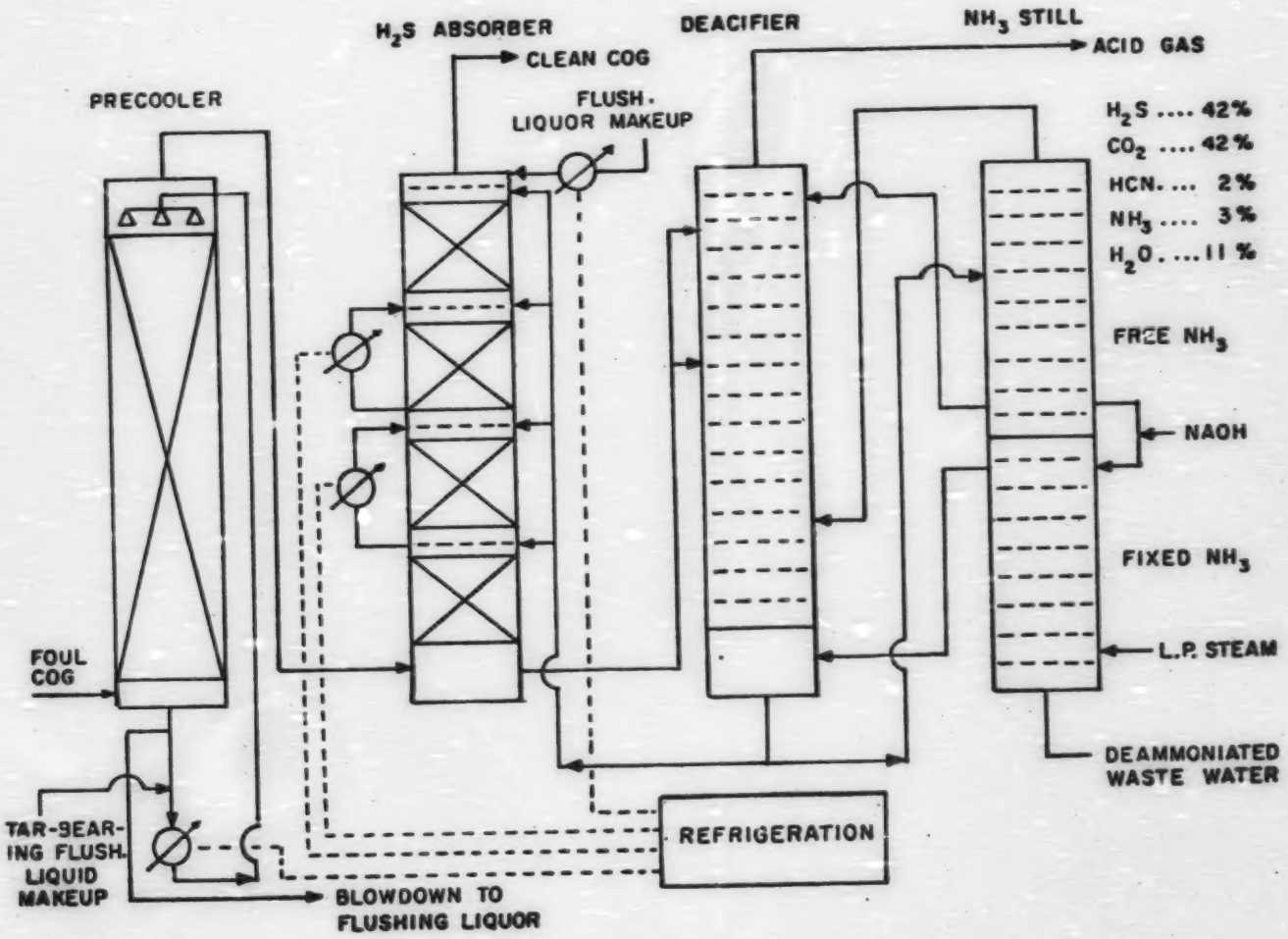


Figure 5. Process flowsheet: Dravo-Firma Carl Still process for COG desulfurization[3]

Waste water from the ammonia still is the only liquid effluent. This waste stream can be combined with the normal by-product plant waste ammonia liquor.

Diamox Process

The Diamox process is an ammonia-based liquid absorption system being marketed in the United States by Mitsubushi Chemical.* Successful operation has been demonstrated in Japan on a 250 x $10^6$ scf/day plant. $H_2S$ content of the clean COG is reported to be 8 grains/100 scf.[6]

HCN Treatment for Liquid Absorption Processes

HCN in the acid gases from liquid absorption processes must be treated before sulfur recovery. Corrosion and plugging of Claus plants due to HCN has been a serious problem area. This area has been responsible for most of the reliability and technological problems associated with liquid absorption systems for COG desulfurization. Concentrations of HCN should be below 1 percent for successful operation of normal Claus sulfur recovery systems.

Water washing is the oldest applicable method of HCN removal and was utilized by Koppers on a Vacuum Carbonate system in the late 1940's.[9] After HCN is absorbed it must be recovered as a product or stripped from solution and incinerated. Most steel plants will not be interested in recovering HCN and the costs of stripping and incineration will limit the applicability of this process.

Bethlehem Steel Corporation in conjunction with Black, Sivalls, and Bryson has developed a process incorporating a cyanide destruct reactor to eliminate HCN problems in the operation of Claus plants. Acid gases are

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New York, New York.

preheated, then sent to the reactor where they are blended with a small quantity of air in the presence of a bauxite ca lyst.[16] The following series of reactions results in the elimination of hydrogen cyanide.[17]

$$HCN + 2H_2S + 1/2\ O_2 \longrightarrow CS_2 + NH_3 + H_2O$$

$$HCN + H_2O \longrightarrow NH_3 + CO$$

$$CS_2 + H_2O \longrightarrow COS + H_2S$$

$$COS + H_2O \longrightarrow CO_2 + H_2S$$

$$CO + H_2O \longrightarrow CO_2 + H_2$$

The HCN is destroyed by oxidative sulfurization and by hydrolysis. For each mole of hydrogen cyanide destroyed, one mole of ammonia is produced. Concentrations of carbon dioxide, carbon monoxide, and organic sulfides also increase. Typical compositions of acid gas streams before and after the cyanide destruct reactor are shown in Table 8.

Since ammonia and organic sulfides are major sources of Claus reactor inefficiency, the following modifications in the Claus unit and operation are required. The burner/oven temperature must be maintained at greater than 1900°F by adding fuel gas as necessary. This causes the pyrolytic decomposition of ammonia to nitrogen and hydrogen. The first catalytic reactor in the Claus unit must be modified to convert organic sulfides to sulfur. A more active catalyst is also necessary.

A full scale cyanide destruct unit and modified Claus unit has proven effective at Bethlehem's Lackawana and Sparrows Point plants. Hydrogen cyanide concentration has been reduced from 16.1 percent to 0.2 percent, and corrosion problems due to HCN have been eliminated.[17] BS&B is currently marketing this system as an integral component of their Sulfiban process. However, the cyanide destruct system can be used with other liquid absorption process. In fact, BS&B has a commitment for construction of an HCN destruct unit and Claus plant on a Vacuum Carbonate system at Inland Steel, Indiana Harbor Works.[12]

Table 8. TYPICAL ACID GAS COMPOSITIONS ACROSS CYANIDE DESTRUCT REACTOR FOR TWO ABSORPTION PROCESSES

| Component | Amine or ammonia absorption process[16] | | Sodium carbonate absorption process[17] | |
|---|---|---|---|---|
| | Cyanide reactor INLET concentration mole % | OUTLET mole % | INLET mole % | OUTLET mole % |
| $H_2S$ | 42.3 | 36.0 | 79.0 | 65.4 |
| $CO_2$ | 51.6 | 48.3 | 10.5 | 12.0 |
| HCN | 4.4 | 0.2 | 7.8 | 0.2 |
| $O_2$ | - | - | - | - |
| $N_2$ | - | 6.9 | - | 6.9 |
| $CS_2$ | 0.4 | 0.7 | - | 0.6 |
| COS | - | 1.3 | - | 2.0 |
| CO | - | 0.6 | - | 1.2 |
| $NH_3$ | - | 3.7 | - | 6.6 |
| $H_2$ | - | 1.4 | - | 2.6 |
| Other | 1.2 | 1.1 | 2.7 | 2.4 |

A catalytic cracking process for decomposing HCN has been developed by Firma Carl Still and utilized in Germany with success.[13] This system operates at 1500 to 2000°F and is incorporated as part of a modified Claus furnace. The HCN is cracked to $H_2 + CO + N_2$, and any traces of $NH_3$ remaining in the acid gas stream are also converted to $N_2 + H_2$ as in the Sulfiban system. Dravo is marketing this system as part of the Dravo-Still process in the United States.

A fourth approach has been investigated by Koppers. This modification of the Claus plant combustion chamber to improve HCN incineration was installed on a Vacuum Carbonate system,[9] Bethlehem Steel Corp., Burns Harbor, Indiana.

## WET OXIDATIVE PROCESS

Wet oxidative processes differ from liquid absorption systems in that $H_2S$ is oxidized to elemental sulfur while still in the absorbing medium. Elemental sulfur is then simply recovered, without a Claus plant, by filtration. In this type of system the steam consumption is greatly reduced, about 80 to 90 percent, as the stripping step is eliminated. In addition capital costs may be lower since a Claus plant or a sulfuric acid plant is not needed. However, HCN is a very serious problem for these systems and must be removed before it enters the absorber or consumption of the expensive chemicals will be excessive.

### Holmes-Stretford Process

The complete Holmes-Stretford process now being marketed by Wilputte* in the United States uses the Holmes process for treatment of liquid waste streams resulting from HCN absorption and the Stretford wet oxidative system for $H_2S$ absorption. Dominion Foundry and Steel Ltd., in Hamilton, Ontario, Canada is the only plant in North America using the Stretford process. They have ordered a Holmes fixed salt recovery system for treatment of the liquid waste stream.[18]

A process flow sheet for the Stretford process is presented in Figure 6. Vanadium, anthraquinone disulfonic acid, anhydrous citric acid, and $Na_2CO_3$ are circulated through the absorber. After $H_2S$ is dissolved in the liquid

*Wilputte Corporation
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Murray Hill, N.J. 07974

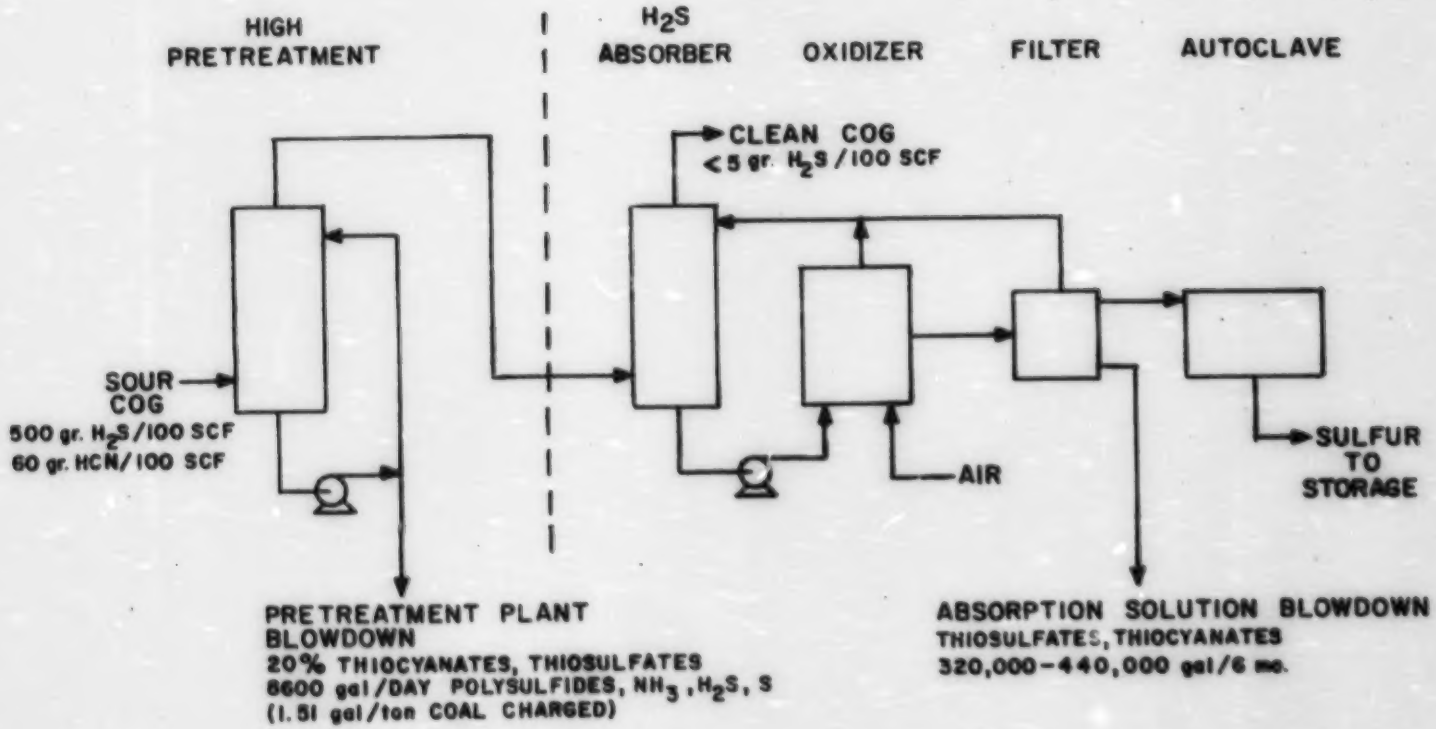


Figure 6. Process flowsheet: The Stretford Process[9]

it is oxidized to sulfur as the vanadium is reduced from its pentavalent form to its quadrivalent state. The anthraquinone disulfonic acid is employed as an oxidant to regenerate the vanadium to the pentavalent state. During this reaction, the anthraquinone is reduced to semiquinone which is oxidized back to anthraquinone with air. This absorption oxidation system is capable of achieving $H_2S$ removal efficiencies of over 99 percent but does not remove organic sulfur. There is no tail-gas; thus overall sulfur removal efficiency is primarily a function of the concentration of organic sulfides in the COG.

The chemical reagents used in the Stretford process react irreversibly with HCN to form thiocyanates and other salts. This increases the amount of blowdown needed and the make-up chemicals required. Besides increasing the quantity of waste from the process, chemical costs can be prohibitive (anthraquinone disulfonic acid costs about $5/lb). HCN must therefore be removed before the absorber.

Dominion Foundry is using a polysulfide pretreatment system with an ammonia absorbent. Dominion has been able to achieve a 90 percent cyanide removal efficiency, and higher removal efficiencies may be possible using a sodium-based absorbent.[18] Wilputte is currently using sodium carbonate in their pretreatment systems. The reactions within the system proceed as follows:

$$Na_2CO_3 + H_2S \rightarrow Na_2S + CO_2 + H_2O$$

$$Na_2S + S_n \rightarrow Na_2S_{(n+1)}$$

(formation of polysulfides)

$$HCN + Na_2S_{(n+1)} + Na_2CO_3 \rightarrow NaCNS + NaHCO_3 + Na_2S_n$$

(destruction of cyanide)

$$Na_2S_n + S \rightarrow Na_2S_{(n+1)}$$

(regeneration of polysulfides)

The reactions are carried out by passing the COG countercurrent to the sodium polysulfide wash liquor in a scrubbing tower. A sidestream of the circulating liquor is withdrawn and passed through the polysulfide regenerator. A blowdown stream purges reacted salts.

The major problem with the Stretford process is the large quantity of liquid waste containing high concentrations of thiocyanates, polysulfides, thiosulfates, etc. This problem has limited the application of the Stretford system up to this time. These wastes can reportedly be treated by the Holmes process in which the effluent is incinerated in a refractory-lined furnace under proprietary conditions. The products are recycled, and there are no effluent streams but anthraquinowe disulfonic acid and sulfur are consumed. The first full-scale system began operation at the British Steel Corporation Orgreave Works in July, 1975. After the initial start-up and shakedown period, the fixed salts recovery system reportedly has worked well.[19] Although Dominion Foundry has contracted to purchase a Holmes system, the technical feasibility remains to be commercially demonstrated in North America.

## $SO_2$ CONTROL METHODS FOR SMALL COAL-FIRED BOILERS

Several methods are available to reduce $SO_2$ emissions from boiler D to the required 2.22 lb $SO_2/10^6$ Btu emission rate. Based on the process description in Section II a flue gas desulfurization system designed to clean 20,000 to 35,000 scfm could be used to comply with the proposed regulation. An alternative approach would be to use a coal with the present heating value of 11,500 Btu/lb but containing 1.35 to 1.6 percent sulfur instead of 2 percent sulfur.

### Flue Gas Desulfurization Systems

There are many flue gas desulfurization processes either currently in use or under development for control of $SO_2$ emissions from coal-fired

boilers. These methods include wet scrubbing with lime, limestone, magnesium oxide, sodium sulfite (Wellman-Lord), sodium hydroxide (double alkali) and sodium citrate. Catalytic oxidation, dry adsorption on carbonaceous materials, absorption by molten carbonate and other processes are also being developed. Many of these processes are not applicable to small industrial coal-fired boilers due to the poor economics of small scale systems. GCA has selected the Bahco system, a wet scrubbing process using lime, manufactured by Research-Cottrell and the FMC double alkali system for evaluation in this study. These two systems were selected because they are specifically designed and marketed for application to industrial coal-fired boilers and because the technology has been demonstrated.

Lime Scrubbing - Lime scrubbing systems are manufactured by numerous engineering construction firms and have been in use on utility boilers for several years. Although lime scrubbing is very similar to limestone scrubbing there are several potential advantages in using lime, particularly for smaller systems. Raw material transport costs are lower, maintenance and scaling may be reduced, raw material utilization is more effective, and solid waste quantities are slightly lower. Table 9 summarizes the status of lime scrubbing systems.

The Research-Cottrell* Bahco-lime scrubbing system (see Figure 7) consists of a two stage venturi. The first venturi presaturates the gas, removes some $SO_2$ and may be designed to remove particulates. At the bottom of the column, flue gas is directed down against the surface of a milk lime slurry. The high velocity gas-liquid contact produces a vigorous cascade of droplets that carry up into the first scrubber stage for turbulent mixing with the flue gas. Above the first venturi, droplets are separated in an inertial collector while the gas continues up to a second stage

*Research-Cottrell, P.O. Box 750, Bound Brook, N.J.

## Table 9. STATUS OF LIME FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[20,21]

| Utility company power station | Size of FGD unit, MW[a] | Vendor/process | Fuel characteristics | Startup date, mo/yr | Availability, % |
|---|---|---|---|---|---|
| **Operational systems** | | | | | |
| Duquesne Light Elrama | 510 | Chemico/ Lime Scrubbing | Coal - 1.0 - 2.8 percent sulfur | 10/73 | - |
| Duquesne Light Phillips | 410 | Chemico/ | Coal - 1.0 - 2.8 percent sulfur | 7/73 | 73 |
| Kentucky Utilities Green River - Units 1 & 2 | 64 | American Air Filter/ lime scrubbing | Coal - 3.8 percent sulfur | 10/75 | - |
| Louisville Gas & Electric Paddys Run No. 6 | 65 | Combustion Engineering/ lime scrubbing | Coal - 3.5 - 4.0 percent sulfur | 4/73 | 58 |
| Montana Power Co. Colstrip No. 1 | 360 | Combustion Equip. Associates/ lime scrubbing | Coal - 0.8 percent sulfur | 10/75 | - |
| Rickenbacker AFB Rickenbacker | 42 | Research Cottrell/ lime scrubbing | Coal - 3.6 percent sulfur | 3/76 | 90 |
| Pennsylvania Power Co. Bruce Mansfield No. 1 | 835 | Chemico/ lime scrubbing | Coal - 4.3 percent sulfur | 10/75 | 8 |
| Tennessee Valley Authority Shawnee No. 10 | 30 | Tennessee Valley Authority lime/limestone scrubbing | Coal - 2.9 percent sulfur | 4/72 | - |
| Arizona Public Service Four Corners No. 5A | 160 | SCE/lime scrubbing | Coal - 0.7 percent sulfur | 2/76 | - |
| **Systems under construction** | | | | | |
| Columbus & Southern Ohio Elec. - Conesville No. 5 | 400 | Universal Oil Products/ lime scrubbing | Coal - 4.5 - 4.9 percent sulfur | 6/76 | - |
| Louisville Gas & Electric Cane Run No. 4 | 178 | American Air Filter/ lime scrubbing | Coal - 3.5 - 4.05 percent sulfur | 6/76 | - |
| Louisville Gas & Electric Cane Run No. 5 | 183 | Combustion Engineering/ lime scrubbing | Coal - 3.5 - 4.05 percent sulfur | 12/77 | - |
| Louisville Gas & Electric Mill Creek No. 3 | 425 | American Air Filter/ lime scrubbing | Coal - 3.5 - 4.0 percent sulfur | 7/77 | - |

[a]One MW is approximately equivalent to 10 x $10^6$ Btu/hr fuel input and 2200 scfm flue gas.

Table 9 (continued). STATUS AND LIME FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[20,21]

| Utility company power station | Size of FGD unit, MW[a] | Vendor/process | Fuel characteristics | Startup date, mo/yr | Availability, % |
|---|---|---|---|---|---|
| **Systems under construction** | | | | | |
| Montana Power Co. Colstrip No. 2 | 360 | Combustion Equip. Associates/ lime scrubbing | Coal - 0.8 percent sulfur | 7/76 | - |
| Pennsylvania Power Co. Bruce Mansfield No. 2 | 835 | Chemico/ lime scrubbing | Coal - 4.3 percent sulfur | 4/77 | - |
| Utah Power & Light Co. Huntington No. 1 | 415 | Chemico/ lime scrubbing | Coal - 0.5 percent sulfur | 6/77 | - |
| **Contracts awarded - engineering design phase of development** | | | | | |
| Columbus & Southern Ohio Elec. - Conesville No. 6 | 400 | Universal Oil Products/ lime scrubbing | Coal - 4.5 - 4.9 percent sulfur | 1/78 | - |
| Allegheny Power System Pleasants No. 1 | 625 | Babcock & Wilcox/ lime scrubbing | Coal - 2.0 - 5.0 percent sulfur | 3/79 | - |
| Allegheny Power System Pleasants No. 2 | 625 | Babcock & Wilcox/ lime scrubbing | Coal - 2.0 - 5.0 percent sulfur | 3/80 | - |
| Utah Power & Light Co. Emery No. 1 | 400 | Chemico/ lime scrubbing | Coal - 0.5 percent sulfur | 6/78 | - |

[a]One MW is approximately equivalent to $10 \times 10^6$ Btu/hr fuel input and 2200 scfm flue gas.

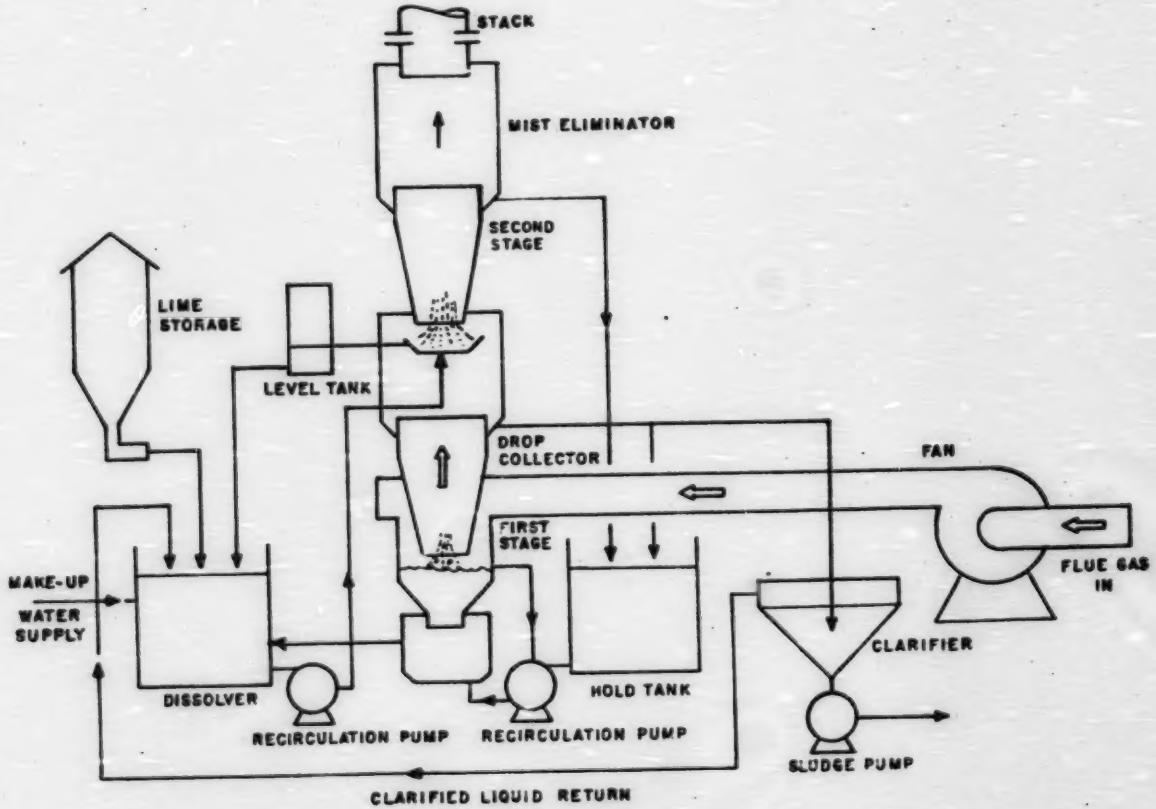


Figure 7. Research-Cottrell (Bahco) scrubber system[22]

where the gas-liquid contact process is repeated. A mist eliminator above the second stage frees the gas of droplets prior to exiting the stack. Separated liquids from both stages of the venturi return to the lower impingement zone. A fraction of this return flow is continuously removed for disposal, usually to a thickener. Clarified liquid is returned to the lime dissolving tank to minimize makeup requirements.[22] Operating and design characteristics of the Bahco system are summarized in Table 10.

Double Alkali Scrubber Systems

A double alkali scrubber system has been developed by FMC Corporation* and is currently in operation and being marketed commerically. The process involves a sodium-based scrubbing loop in which the sulfur dioxide in flue gas is collected according to the following reactions:

$$Na_2CO_3 + H_2O \rightarrow 2NaOH + CO_2$$

$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

and subsequently precipitated with calcium in a separate loop according to the reaction

$$2NaHSO_3 + Ca(OH)_2 \rightarrow CaSO_3 + Na_2SO_3 + 2H_2O$$

This system was developed primarily to alleviate scaling problems initially encountered with lime/limestone systems. The spent scrubber solution which is primarily composed of sodium bisulfite ($NaHSO_3$) is pumped to a lime reactor where it mixed with slaked lime. In the reactor, sodium

*FMC Corporation, Environmental Equipment Division, 21 Charles Street, Westport, Conn.

Table 10. RESEARCH-COTTRELL LIME (BAHCO) SCRUBBING SYSTEM[21,23]

| | |
|---|---|
| Smallest system capacity commercially available (scfm) | 20,000 |
| Overall pressure drop through system (in $H_2O$) | 16 - 26 |
| Turndown ratio of system [a] | 1.5 - 1 |
| $SO_2$ removal efficiency, percent | 90 - 99 |
| Raw materials | Lime |
| By-products | None |
| Wastes [b] lb waste/lb $SO_2$ removed | 6.1 lb cake containing 35 percent solids ($CaSO_3$ and $CaSO_4$) and 65 percent water |
| Maintenance | Scaling and solids deposition appear to be less severe than for limestone based scrubbing systems. Corrosion can be minimized by properly designing the system. |
| Development status | Operational systems<br>55,000 scfm 3.6% S coal |

[a] Any turndown ratio maybe accommodated by the addition of makeup air.

[b] Does not include the fly ash that would be removed.

bisulfite is converted to sodium sulfite ($Na_2SO_3$) and calcium sulfite ($CaSO_3$) is precipitated out, thickened and put through a rotary drum vacuum filter. The sodium sulfite solution is then recirculated back to the scrubber. Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to sodium sulfate. These chemical losses are offset with makeup soda ash.[24] A schematic of FMC's double alkali scrubber system is presented in Figure 8. Table 11 presents pertinent design and operating data for the FMC double alkali scrubbing system.

Sludge Disposal

Nonregenerative scrubbing systems for $SO_2$ control produce sludges that must be utilized or disposed. Sludges produced by lime and limestone $SO_2$ scrubbing systems contain primarily calcium sulfite, calcium sulfate, calcium carbonate and fly ash. Trace metals resulting primarily from coal ash components are also present in the sludge. Water content is typically 50 to 80 percent. An environmentally acceptable method for sludge disposal or utilization must be considered in the evaluation of the technical feasibility and cost of scrubbing. Numerous options have been proposed for sludge utilization[26,27] but significant application of these techniques especially to small systems appears to be unlikely. A recent EPA-sponsored study concluded that ponding and landfill are the only near term alternatives for sludge disposal.[28]

Ponding is currently the most commonly used lime/limestone sludge disposal method. All wet scrubbing systems present the potential problem of direct waste water discharge to surface waters. Eight full scale systems representing over 1500 Mw of boiler capacity have eliminated this problem by recirculating the scrubber liquor; i.e., closed loop operation.[29] Other installations recirculate as much of the liquor as technically feasible. Pollution of ground and surface waters from leachate formation is also a potential problem. Ponds may be lined with clay or synthetic materials like asphalt, PVC, Hypalon, etc.[30] The

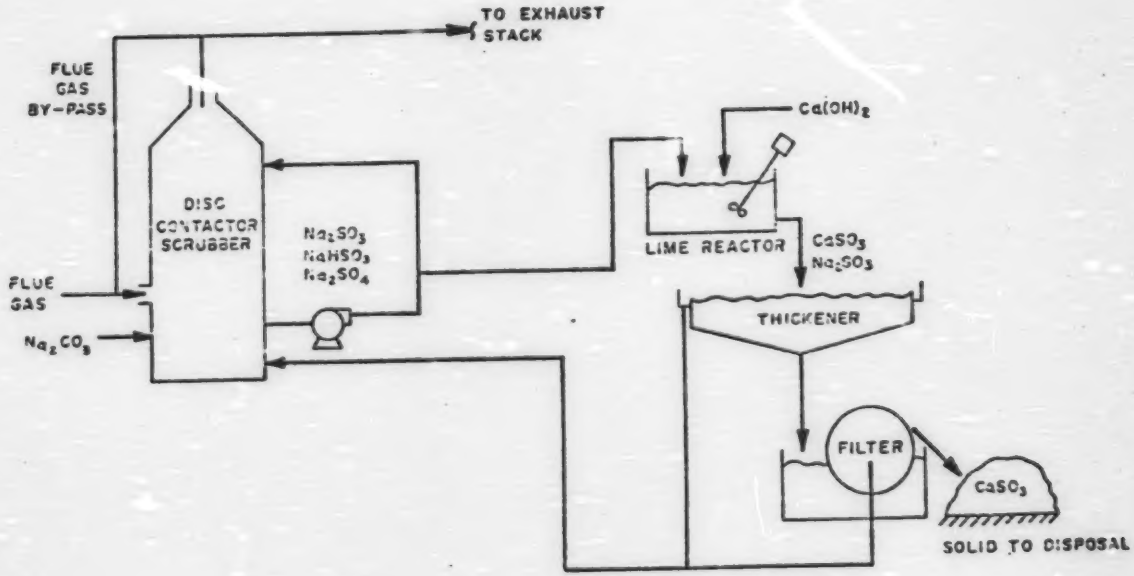


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Figure 8. FMC double alkali scrubber system[24]

Table 11. FMC DOUBLE ALKALI SCRUBBING SYSTEM[25]

| | |
|---|---|
| Smallest system capacity commercially available (scfm) | 33,000 |
| Overall pressure drop through system (in $H_2O$) | 5 - 15 |
| Turndown ratio of system | 4:1 |
| $SO_2$ removal efficiency, percent | 90 - 95 |
| Raw materials | Lime (CaO), soda ash ($Na_2CO_3$) |
| By-products | None |
| Wastes[a] lb waste/lb $SO_2$ removed | 5.8 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$ and $Na_2SO_4$) and 65 percent water |
| Maintenance | This system is designed such that scaling is not a problem. Corrosion problems can be minimized with proper system design. |
| Development status | Operational systems<br>3 MW; 2 % S coal; 90 % $SO_2$ removal 94 % availability; operating since 1/75<br>57 MW; 3.2 % S coal; 90 % $SO_2$ removal 100 % availability; operating since 10/75<br>Systems in engineering design and construction phase of development<br>95 MW; 3.2 % S coal; startup slated for 1977<br>93 MW; 3.2 % S coal; startup slated for 1978 |

[a]Does not include the fly ash that would be removed.

necessity for lining and/or stabilization depends on local regulations, sludge characteristics and local geology and hydrology. Currently, only Commonwealth Edison, Will County No. 1, is using a lined (clay) pond[20] but future requirements will probably be more stringent.

Costs for sludge disposal by ponding can vary widely, depending on land cost; the type of liner used, if any; location of the pond in relation to the scrubbers; and the settling characteristics of the sludge. The need for a pond liner and the type used and therefore the disposal cost will depend on local geology, hydrology and environmental regulations. It has been suggested that the small industrial boilers may present reduced sludge disposal problems as local environmental impacts will be limited.[31] Aerospace Corporation has conducted a detailed evaluation of ponding[30] and is currently continuing programs in the area. Data from this initial study have been updated and cost ranges are $0.2 to $3 per ton of sludge (50 percent solids) for unlined pond disposal and $0.5 to $10 per ton of sludge for line pond disposal.[28] The large range and higher upper limits reflect uncertainty in regard to unusual local situations. A cost of $3 per ton for sludge disposal in a lined pond was reported to be typical. Costs would be nearer $1 per ton if disposal in an unlined pond is allowed. Typical truck hauling rates for stabilized fly ash for a distance of 5 miles are reported to be $0.75/ton.[28] This may represent an added cost when offsite ponding or landfill is required. Based on the above data, GCA used a cost of $4/ton for sludge disposal.

Landfill is also a viable disposal option although use of this option is currently limited. Large scale landfills utilized by utilities would be 1 to 2 orders of magnitude larger than the landfill that would be needed for boiler D. These large landfills would probably require extensive

sludge dewatering and in some cases chemical fixation. Small amounts of dewatered sludge might be disposed in a municipal sanitary landfill or mixed with other steel plant wastes for disposal.

Sludge from sodium-based double alkali systems have been less intensively investigated. A major difference between sludges from lime/limestone systems and double alkali systems is that the former are primarily calcium sulfate ($CaSO_4$) while the latter are primarily calcium sulfite ($CaSO_3$). One might expect, in view of the dewatering problems attributed to minor amounts of $CaSO_3$ in lime/limestone sludge, that double alkali sludge would be difficult to dewater. However, FMC has investigated vacuum filtration and landfilling of double alkali sludge and reports success in both areas.[24] Perhaps the different conditions under which the sludges form also affects the properties.

While sludge disposal is an important environmental consideration, disposal methods are available and the annual cost should be relatively small, less than 10 percent of the total annual FDG cost.

## LOW SULFUR COAL AND OTHER $SO_2$ EMISSION REDUCTION ALTERNATIVES

The use of low sulfur coal and/or mechanical coal cleaning are potential methods for complying with the proposed $SO_2$ regulations. These options will be particularly attractive in counties with the least stringent emission limitations.

The sulfur content of coal needed to comply with the proposed regulations varies as the emission limit varies from 0.6 lb $SO_2/10^6$ Btu to 6.8 lbs $SO_2/10^6$ Btu in those counties that are regulated. Therefore, the sulfur content of "low sulfur" or compliance coal needed to comply with the

proposed regulations will vary as shown in Table 12, assuming a heating value of 12,000 Btu/lb. The sulfur content of these compliance coals is higher than the 1 percent level defined as low sulfur coal in many studies. Large quantities of coal with sulfur contents in the required ranges are used by the industrial sector in Ohio. Coal shipments to Ohio industry, not including electric utilities and coke and gas plants, in 1972 totaled 12,700,000 tons of which 11 percent contained 1.1 to 1.3 percent sulfur, 6 percent contained 1.4 to 1.8 percent sulfur, 35 percent contained 1.9 to 3.0 percent sulfur and the remaining 48 percent contained above 3 percent sulfur.[31]

Coal supply district 4 (all of Ohio) provides 53 percent of industrial coal consumed in Ohio while district 8 (southern West Virginia, parts of Virginia, eastern Kentucky and northern Tennessee) provides 40 percent.[32] This industrial coal supply pattern is different from Ohio utility coal supply which consists of 64 percent district 4 coal, and only 15 percent district 8 coal. Therefore, it is evident that supply

Table 12. $SO_2$ EMISSION LIMITATIONS AND EQUIVALENT PERCENT SULFUR IN COAL[a]

| lb $SO_2/10^6$ Btu | Percent Sulfur in coal |
|---|---|
| 0.6 | 0.36 |
| 1.0 | 0.60 |
| 1.5 | 0.90 |
| 2.0 | 1.2 |
| 2.5 | 1.5 |
| 3.0 | 1.8 |
| 4.0 | 2.4 |
| 5.0 | 3.0 |
| 6.0 | 3.6 |
| 6.8 | 4.1 |

[a]Based on a heating value of 12,000 Btu/lb and 100 percent conversion of fuel sulfur to $SO_2$.

and transport routes from district 8 are available to and utilized by Ohio industry. This is important because district 8 coal is commonly low in sulfur content and reserves of compliance coal are very large.

The reserve base of mineable coal in West Virginia, Kentucky and Ohio is presented in Table 13. These listed reserves include only measured and indicated coal seems greater than 28-inches thick and less than 1000 ft deep for deep mining and with less than 120 feet of overburden for strip mining. Reserves within these three states are large when compared to the 66 million tons/year currently used by all ohio consumers. Perspective on the amount of reserves may also be gained by comparison of the current U.S. consumption of about 600 million tons/year to the West Virginia reserves of 40,000 million tons total and 18,400 million tons of less than 1.5 percent sulfur coal. Even Ohio has significant reserves of coal that would comply with many of the regulations. A shift in consumption patterns by Ohio industry which uses about 12 million tons of coal per year should not affect coal supply and prices. However, a change in consumption patterns by Ohio utilities and neighboring states may affect coal prices. There may be delays in opening new mines and if demand for compliance coal out-paces the increase in supply, prices will certainly increase. These complicating factors make the prediction of future prices very uncertain.

Many Ohio industrial facilities obtain coal by spot purchases. Prices for spot purchases, FOB mine, as reported in Coal Week during 1975 indicate that district 8 coal with a sulfur content of 1.25 percent was less expensive than Ohio coal with an average sulfur content of 3.2 percent. In December 1975 Ohio spot purchased coal was $17.5/ton and district 8 coal was $14.25/ton.[34] In his testimony at the January 8, 1976 public hearing, A. L. Susman, Chairman, Mines and Mining Subcommittee, West Virgina Senate, reported several indications of a lack of demand for low sulfur coal and significant idle mines capable of producing less than 1 percent sulfur coal.[35] When switching from one coal to another, many coal properties including ash composition, ash fusion

Table 13. BITUMINOUS COAL RESERVE BASE FOR SELECTED STATES, THICKNESS, TYPE OF MINING; AND SULFUR RANGE - JANUARY 1, 1974 (MILLION SHORT TONS)[33]

| | RESERVES BY SULFUR RANGE, PERCENT | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Thickness | ≤ 0.4 | 0.5 - 0.6 | 0.7 - 0.8 | 0.9 - 1.0 | 1.1 - 1.4 | 1.5 - 1.8 | 1.9 - 2.2 | 2.3 - 2.6 | 2.7 - 3.0 | > 3.0 | Unknown | Total |
| West Virginia | | | | | | | | | | | | |
| Deep > 28 | 229.19 | 2923.45 | 4948.83 | 2985.13 | 3696.23 | 2615.11 | 2435.13 | 2057.71 | 1779.23 | 6552.88 | 4142.92 | 34377.77 |
| Strip > 28 | 44.12 | 799.33 | 1363.37 | 798.64 | 581.16 | 262.61 | 239.14 | 191.94 | 147.97 | 270.40 | 509.55 | 5212.02 |
| Total | 273.31 | 3722.78 | 6312.20 | 3783.77 | 4277.39 | 2877.72 | 2674.27 | 2249.65 | 1927.20 | 6823.28 | 4652.47 | 39589.79 |
| Kentucky | | | | | | | | | | | | |
| Deep > 24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.39 | 1.19 | 70.44 | 314.56 | 7226.36 | 1107.11 | 8719.89 |
| Strip > 24 | 0.00 | 0.00 | 0.00 | 0.22 | 0.83 | 8.53 | 22.22 | 45.20 | 101.05 | 2017.45 | 1708.79 | 3904.02 |
| Total | 0.00 | 0.00 | 0.00 | 0.22 | 0.83 | 8.92 | 23.41 | 115.64 | 415.61 | 9243.81 | 2815.90 | 12623.91 |
| Ohio | | | | | | | | | | | | |
| Deep > 28 | 0.00 | 9.09 | 37.49 | 68.87 | 318.26 | 693.25 | 954.59 | 1414.95 | 2068.83 | 10109.36 | 1754.09 | 17423.26 |
| Strip > 28 | 0.00 | 2.97 | 5.27 | 10.63 | 41.55 | 93.05 | 192.70 | 310.27 | 353.39 | 2524.87 | 117.93 | 3653.89 |
| Total | 0.00 | 12.06 | 42.76 | 79.50 | 359.81 | 786.30 | 1147.29 | 1725.22 | 2422.22 | 12634.23 | 1872.02 | 21077.15 |

temperature, moisture content, etc., can affect boiler performance.[2] A suitable coal supply can only be determined on a case-by-case basis due to variations in the regulations and required fuel specifications. For the sites visited in this study GCA telephoned suppliers to determine current prices for coal with the required sulfur contents.

Mechanical coal cleaning has been widely used for many years and in 1973 about 50 percent of total coal consumption was cleaned coal.[36] Many of the systems now in operation, however, were designed primarily for ash removal. All coal used for coking (17 percent of total coal consumed and 33 of cleaned coal consumption) is cleaned to reduce both the sulfur and ash content. Coal cleaning technology is clearly commercially proven but its effectiveness depends on the properties of the specific coal being cleaned. A summary of the application of mechanical coal cleaning in 1973 is presented in Table 14. Most West Virginia coal is cleaned but much greater sulfur reduction could probably be achieved through process improvements. On the other hand, less than half of Ohio coal production is cleaned and increased application of coal cleaning as well as improvement of existing systems could greatly reduce the sulfur and ash content.

Mechanical coal cleaning separates coal constituents with different specific gravities, as shown in Table 15. Sulfur is present in coal both as pyritic sulfur, which can be separated, and organically bound sulfur which cannot be mechanically removed. The pyritic sulfur composes 20 to 80 percent of the total sulfur with the lower percentage usually found in lower sulfur coals.[37] Analysis of Ohio coals indicates that about half the sulfur is present as organic sulfur.[38] Crushing frees the pyritic sulfur particles from other coal particles and is the first step in mechanical cleaning. Coal is commonly crushed to less than 1-1/2 inches or less than 14 mesh and smaller in certain cases. The finer size produces better sulfur removal but the crushed coal is harder to handle and cleaning costs increase. Wet

Table 14. MECHANICAL CLEANING AT BITUMINOUS COAL AND LIGNITE MINES, IN 1973 BY STATE (THOUSAND SHORT TONS)[36]

| State | Total production | Mechanical cleaning | | | |
|---|---|---|---|---|---|
| | | Number of cleaning plants | Raw coal | Cleaned coal | Refuse |
| Alabama | 19,230 | 19 | 18,433 | 11,705 | 6,728 |
| Alaska | 694 | 1 | 70 | 50 | 20 |
| Colorado | 6,233 | 3 | 1,933 | 1,662 | 270 |
| Illinois | 61,572 | 36 | 62,386 | 48,091 | 14,295 |
| Indiana | 25,253 | 10 | 25,330 | 19,699 | 5,631 |
| Kentucky: | | | | | |
| Eastern | 73,966 | 33 | 30,359 | 22,264 | 8,095 |
| Western | 53,679 | 18 | 26,004 | 20,005 | 5,999 |
| Total | 127,645 | 51 | 56,363 | 42,269 | 14,094 |
| Ohio | 45,783 | 17 | 20,799 | 14,588 | 6,211 |
| Oklahoma | 2,183 | 3 | 381 | 312 | 69 |
| Pennsylvania | 76,403 | 68 | 63,041 | 45,731 | 17,310 |
| Tennessee | 8,219 | 2 | 1,575 | 1,145 | 430 |
| Utah | 5,500 | 7 | 4,156 | 3,375 | 581 |
| Virginia | 33,961 | 32 | 26,559 | 17,696 | 8,863 |
| Washington | 3,270 | 2 | 4,460 | 3,262 | 1,198 |
| West Virginia | 115,448 | 124 | 107,520 | 75,672 | 31,848 |
| Other States[a] | 60,344 | 7 | 4,639 | 3,460 | 1,179 |
| Grand total[b] | 591,738 | 382 | 397,646 | 288,918 | 108,728 |

[a]Includes Arizona, Arkansas, Iowa, Kansas, Maryland, Missouri, Montana (bituminous coal and lignite), New Mexico, North Dakota (lignite), and Wyoming.

[b]Data may not add to totals shown because of independent rounding.

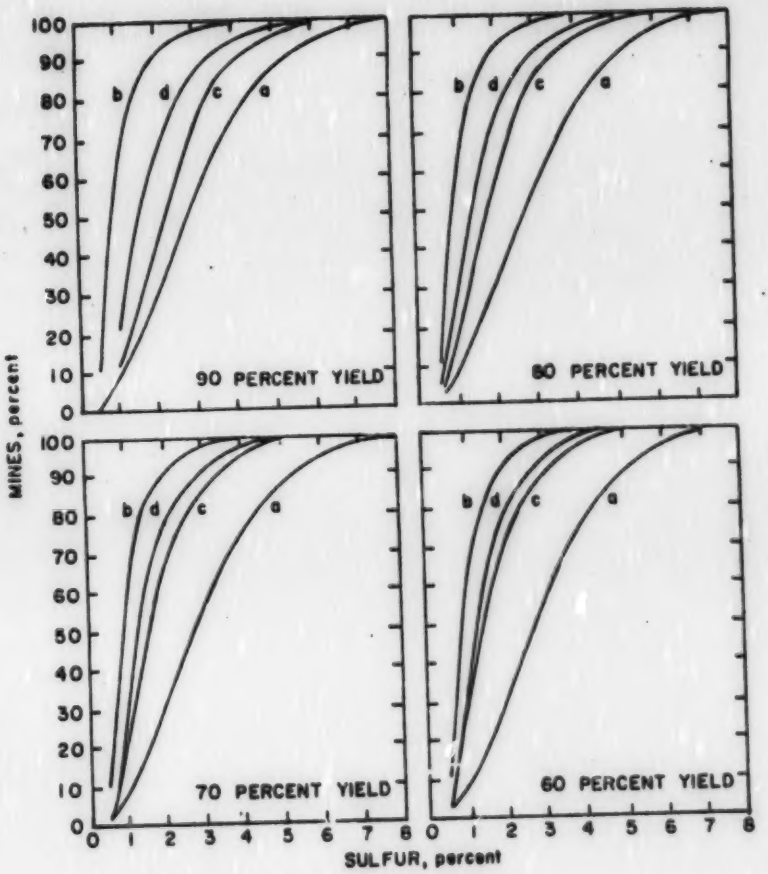
concentrating tables, compound water cyclones, air classification, froth flotation and concentrating spirals are widely used conventional commercially available methods for density separation in coal cleaning.[39] The net costs for mechanical coal cleaning are difficult to assess due to variations in coal washability. The Commerce Technical Advisory Board reported mid-1974 costs of $1.2 to $2.2/ton for crushing to 3/8 inch with single stage separation and $2.9 to $4.8/ton for a more elaborate multistage separation of finer particles.[40] Cost projections in Coal Age indicate a range of $6.5 to $9/ton to clean Appalachian coal to less than 1 percent sulfur.[41] An update by GCA for cost data reported by Battelle,[42] indicates a current coal cleaning cost of $6/ton of product for removal of pyritic sulfur for the conditions used by Battelle.

Table 15. SPECIFIC GRAVITIES OF COAL AND IMPURITIES

| Material | Specific gravity |
|---|---|
| Bituminous coal | 1.12 - 1.35 |
| Bone coal | 1.35 - 1.7 |
| Carbonaceous shale | 1.6 - 2.2 |
| Shale | 2.0 - 2.6 |
| Clay | 1.8 - 2.2 |
| Pyrite | 4.8 - 5.2 |

Several cost benefits must be balanced against the coal cleaning costs. Coal cleaning reduces the ash content by 60 to 70 percent, and increases the heating content. Therefore, coal transport costs and ash handling and disposal costs are reduced. Boiler operation is potentially improved by reduced slagging, reduced need for particulate control, improved boiler availability and lower boiler operating and maintenance costs.[36] The Commerce Technical Advisory Board concluded that coal cleaning with or without additional FGD were the least expensive options for utility systems to meet the new source performance standard of 1.2 lb $SO_2/10^6$ Btu.[41]

Washability studies conducted on Northern Appalachian coals (Maryland, Ohio, Pennsylvania, Northern West Virginia) showed that coals from 20 percent of the mines could be washed to less than 1 percent sulfur and coal from 65 percent of the mines could be washed to less than 2 percent sulfur at a 90 percent yield when crushed to -14 mesh.[39] These results are summarized in Figure 9. The washed coals discussed above contained only 5 to 7 percent ash and had a heating value of about 13,000 Btu/lb.[39] Coals from the Northern Appalachian region are used extensively in Ohio. Washability studies were also conducted on Southern Appalachian coals, roughly equivalent to coal supply district 8, showing that samples from 90 percent of the mines could be reduced to less than 1 percent sulfur at a 90 percent yield when crushed to -14 mesh.[39]




(a) RAW COAL TOTAL SULFUR CONTENT CURVE;

(b) RAW COAL ORGANIC SULFUR CONTENT CURVE;

(c) WASHED COAL TOTAL SULFUR CONTENT COAL CURVE WHEN RAW COAL WAS CRUSHED TO MINUS 1 ½ INCHES; AND,

(d) WHEN RAW COAL WAS CRUSHED TO MINUS 14 MESH.

SOURCE: REFERENCE 39

Figure 9. Washability of northern Appalachian region coals

## SECTION IV

## COST OF $SO_2$ CONTROL METHODS

Cost of $SO_2$ control to desulfurize both coke oven gas and flue gas were estimated by GCA. For two COG desulfurization systems to treat 46 x $10^6$ scfd and 33 x $10^6$ scfd the capital investment was $14 to $15 million and the total annual cost was $3.4 to $3.8 million or $0.23 to $0.26/lb sulfur collected. At capacity, COG desulfurization to comply with the proposed regulation would reduce $SO_2$ emissions by 14,700 ton/year. The capital cost for flue gas desulfurization applied to boiler D to meet the proposed regulation was $1.4 million while the total annual cost was $462,000 or $0.275 per pound of sulfur collected. Compliance with proposed regulation would reduce $SO_2$ emissions from boiler D by 840 ton/year.

### COST OF COKE OVEN GAS DESULFURIZATION

To obtain accurate control equipment costs, GCA asked four engineering-construction firms to supply copies of quotations previously submitted to Republic Steel in December, 1975. The quotations were for a desulfurization system as specified in Section II and including sulfur recovery as elemental sulfur. Wilputte;[43] Black, Sivalls, and Bryson;[44] and Dravo[45] provided complete data for the Holmes-Stretford, Sulfiban and Dravo-Still desulfurization processes, respectively. The battery limit plant capital cost estimates supplied by the vendors were based on two COG desulfurization facilities, a 65 x $10^6$ scfd plant and a 33 x $10^6$ scfd plant. Complete operating and annual costs derived for this 98 x $10^6$ scfd system are presented in the Appendix. The costs discussed in detail in this section are for a 46 x $10^6$ scfd plant and a 33 x $10^6$ scfd. These costs

were derived from the vendor estimates for the larger system by GCA. Koppers stated that the Vacuum Carbonate system technology presented in the December 1975 proposal was outdated and declined to supply the requested cost information. For this reason, an economic evaluation of the Vacuum Carbonate system is not included.

The Holmes-Stretford system required the smallest capital investment but the cost differences between the systems were small. Capital cost of the battery limits Holmes-Stretford system was $11.5 million compared to $12.2 million for the Sulfiban units and $12.4 million for the Dravo-Still system. Net operating costs were lowest for the Dravo-Still and Holmes-Stretford control systems. The annualized costs which include an annualized capital charge, federal taxes, and the net operating cost were calculated to be $3.4 million/year for the Holmes-Stretford plants, $3.8 million/year for the Sulfiban system and $3.5 million/year for the Dravo-Still system. The average annual control cost ranged from $0.23 to $0.26/lb sulfur removed. Utility, material and labor requirements, operating costs, and total system costs are discussed in detail in the following subsections.

While the costs presented in this report are the most up to date and accurate data available, they are still not complete engineering designs. Therefore costs are subject to revisions by the vendors. A system should not be selected as the most attractive process solely on the basis of the cost data presented in this report, especially when the costs of the three systems are so close. Future raw material and energy availability and cost must be carefully weighed. Demonstrated performance reliability and manufacturer guarantees are also important selection criteria. All three systems discussed in the following sections are commercially available and can achieve the 50 grains $H_2S$ equivalent/100 scf limitation.

## Utility, Material and Labor Requirements

Detailed utility, material, and labor requirements needed to meet plant operating conditions previously specified are presented in Table 16. This information was based on data submitted by equipment vendors to Republic Steel and GCA. Requirements for the No. 1 plant were revised by GCA to reflect a gas flow of $46 \times 10^6$ scfd instead of $65 \times 10^6$ scfd. Utility and chemical consumption were assumed to be proportional to gas flow. The Wilputte (Holmes-Stretford process) and Dravo (Dravo-Still process) proposals include cooling facilities, hence electric power consumption is greater than the BS&B Sulfiban process, but cooling water requirements are negligible. The BS&B proposal does not include a cooling tower, so cooling water is included under utilities. Because steam is used primarily for stripping acid gases from absorbing solutions, wet oxidative processes (Holmes-Stretford) use only 10 percent of the steam required by liquid absorption - Claus recovery systems (Sulfiban, Dravo-Still). Coke oven gas is used primarily for process heating, but it is also used for Claus plant tail gas treatment by the Dravo system and for liquid effluent treatment by the Holmes-Stretford system.

Material include chemicals used for absorption and oxidation-reductions, and materials necessary for system maintenance. Annual chemical consumption was reported by the equipment vendors. The Holmes-Stretford process uses sodium carbonate, anhydrous citric acid, anthraquinone 2-7-disulfonic acid and sodium ammonium vanadate. Chemical consumption for this process depends strongly on the HCN concentration. The reported chemical requirements are based on a mean cyanide concentration of 39 grains/100 scf at the inlet of the No. 1 system and 21.3 grains/100 scf at the inlet of No. 2 system. A Holmes fixed salts recovery system is incorporated in the process to increase the life of the wash liquor. All vanadium is recovered and recycled except for a small quantity which contaminates the product sulfur (approximately 90 ppm by weight). Monoethanolamine is used as the absorbent in the Sulfiban system and is lost in the sludge blowdown and

Table 16. UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR COG DESULFURIZATION SYSTEMS AT REPUBLIC STEEL - CLEVELAND WORKS TOTAL CAPACITY 79 x $10^6$ scfd[a]

| | Holmes-Stretford | | | Sulfiban | | | Dravo-Still | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total |
| Utility | | | | | | | | | |
| Power, kWh/day | 21,830 | 18,120 | 39,950 | 9,380 | 8,880 | 18,260 | 15,640 | 13,300 | 28,940 |
| Steam, 1000 lb/day | 56.2 | 52.8 | 109.0 | 498.0 | 308.0 | 806.0 | 417 | 260 | 677 |
| Coke oven gas, $10^6$ scfd | 0.17 | 0.17 | 0.34 | 0.35 | 0.27 | 0.62 | 0.054 | 0.031 | 0.085 |
| Water, 1000 gal/day | b | b | b | 5,320 | 3,744 | 9,064 | b | b | b |
| Materials | | | | | | | | | |
| Vanadium, lb/day | 2.5 | 1 | 3.5 | - | - | - | - | - | - |
| Anthraquinone disulfonic acid, lb/day | 131 | 70 | 201 | - | - | - | - | - | - |
| Anydrous citric acid, lb/day | 384 | 200 | 584 | - | - | - | - | - | - |
| Monoethanolamine, lb/day | - | - | - | 611 | 493 | 1,184 | - | - | - |
| K-437 inhibitor (Tretalite), gal/day | - | - | - | 1.4 | 1 | 2.4 | - | - | - |
| Maintenance, percent of fixed capital investment/yr[c] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Labor | | | | | | | | | |
| Operator, man/shift | 1 | 1 | 2 | 1 | 1 | 2 | 1 | 1 | 2 |
| Chemist,[9] hr/day | 2 | 2 | 4 | 2 | 2 | 4 | 2 | 2 | 4 |
| Maintenance, percent of fixed capital investment/yr[c] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |

[a] Based on vendor estimates, May 1976. Plant No. 1 is designed to clean 46 x $10^6$ scfd and plant No. 2 is designed to clean 33 x $10^6$ scfd.

[b] Not significant, cooling towers included in capital and operating costs. Electric power consumption for cooling operation is approximately 35 percent of total.

[c] GCA assumption, similar to estimates used by Massey[9,13] and Choi, et al.[42] for industrial pollution control processes.

carryover from the stripper. A small amount of K-437 inhibitor (Tetralite) is also used in the monoethanolamine solution as a corrosion inhibitor. Net consumption of chemicals in the Dravo-Still system was reported to be negligible. In the absence of hard data on maintenance materials, the cost was assumed to be 1.5 percent of battery limit plant cost per year in line with costs used by Massey[9,13] and Choi, et al.[42]

The equipment vendors reported that one chemical operator per plant per shift is required. Labor requirements for sampling and analysis of COG and tail-gas emission are reported to be 2 hours per plant per day. Maintenance labor is assumed to be equal to the cost of maintenance materials.

Utility, Material, and Labor Costs

Table 17 presents detailed utility, material, and labor costs derived from the requirements noted in Table 15 and the unit costs furnished in Table 17. Total utility, material, and labor cost for a Dravo-Still system (two plants) treating an average of 79 million scfd of coke oven gas is $3600/day. The comparative costs are $4000/day for a Holmes-Stretford system, and $4800/day for a Sulfiban system. The basis for the unit costs used in making these estimates are referenced in Table 17. These operating costs are current as of May 1976.

Capital and Annualized Costs

Capital and annualized costs are presented in Table 18. Costs of battery-limits desulfurization facilities were based on estimates provided by equipment vendors. The estimates were originally submitted to Republic Steel in December 1975. The capital cost of the No. 1 battery-limit plant was revised by GCA on the basis of the gas flow to the 0.6 power from the vendor estimate for a 65 x $10^6$ scfd plant to the required 46 x $10^6$ scfd

Table 17. UTILITY, MATERIAL, AND LABOR COSTS FOR COG DESULFURIZATION SYSTEMS AT REPUBLIC STEEL - CLEVELAND WORKS TOTAL CAPACITY 79 x $10^6$ scfd, $/DAY[a]

| | Holmes-Stretford | | | Sulfiban | | | Dravo-Still | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant No.1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total |
| **Utility** | | | | | | | | | |
| Electric power, $0.02/kWh[b] | 436.7 | 362.4 | 799.1 | 187.6 | 177.6 | 365.2 | 312.8 | 266.0 | 578.8 |
| Steam, $2/1000 lb[c] | 112.6 | 105.6 | 218.2 | 996.0 | 616.0 | 1,612.0 | 834.0 | 520.0 | 1,354.0 |
| Coke oven gas, $250/$10^6$ scf[d] | 42.6 | 42.0 | 84.6 | 87.9 | 67.8 | 155.7 | 13.6 | 7.8 | 21.4 |
| Cooling water, $0.06/1000 gal[e] | - | - | - | 347.6 | 244.6 | 592.2 | - | - | - |
| Total utilities | 591.9 | 510.0 | 1,101.9 | 1,619.1 | 1,106.0 | 2,725.1 | 1,160.4 | 793.8 | 1,954.2 |
| **Material** | | | | | | | | | |
| Vanadium, $5/lb[f] | 10.7 | 5.0 | 15.7 | - | - | - | - | - | - |
| Anthraquinone disulfonic acid, $5.3/lb[f] | 696.8 | 371.0 | 1,067.8 | - | - | - | - | - | - |
| Anhydrous citric acid, $0.5/lb[f] | 191.9 | 100.0 | 291.9 | - | - | - | - | - | - |
| Monoethanolamine, $0.4/lb[g] | - | - | - | 276.4 | 197.2 | 473.6 | - | - | - |
| K-437 inhibitor (Tretalite), $4.5/lb[h] | - | - | - | 6.3 | 4.5 | 10.8 | - | - | - |
| Maintenance, 1.5 percent of fixed capital investment/yr | 299.2 | 266.3 | 565.6 | 361.6 | 241.6 | 603.2 | 337.4 | 276.2 | 613.6 |
| Total material | 1,198.6 | 742.3 | 1,940.9 | 644.3 | 443.3 | 1,087.6 | 337.4 | 276.2 | 613.6 |
| **Labor** | | | | | | | | | |
| Operator, $8/hr | 192.0 | 192.0 | 384.0 | 192.0 | 192.0 | 384.0 | 192.0 | 192.0 | 384.0 |
| Chemist, $8/hr | 16.0 | 16.0 | 32.0 | 16.0 | 16.0 | 32.0 | 16.0 | 16.0 | 32.0 |
| Maintenance, equal to maintenance material | 299.2 | 266.3 | 565.5 | 361.6 | 241.6 | 603.2 | 337.4 | 276.2 | 613.6 |
| Total labor | 507.2 | 474.3 | 981.5 | 569.6 | 449.6 | 1,019.2 | 545.4 | 484.2 | 1,029.6 |
| Total daily operating cost | 2,297.7 | 1,726.6 | 4,024.3 | 2,833.0 | 1,978.9 | 4,831.1 | 2,043.2 | 1,554.2 | 3,597.4 |

[a] See Table 16 for utility, material, and labor requirements.

[b] Ohio Edison.

[c] Based on electricity cost and 10 lb steam/kWh.

[d] Based on $0.5/$10^6$ Btu and a heating value of 500 Btu/scf.

[e] Massey.[9] If cooling tower is included in system, cost of make-up water is assumed to be negligible.

[f] Vilputte Corporation.

[g] Chemical Marketing Reporter, May 1976.

[h] BS&B, Process System Division.

## Table 18. COSTS FOR COG DESULFURIZATION SYSTEMS AT REPUBLIC STEEL-CLEVELAND WORKS TOTAL CAPACITY 79 x $10^6$ scfd, $103

| | Holmes-Stretford | | | Sulfiban | | | Bravo-Still | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total |
| **Capital requirement** | | | | | | | | | |
| Battery limits plant, installed (BLP)[a] | 6,070 | 5,400.0 | 11,470.0 (10,800) | 7,330.0 | 4,900.0 | 12,230 | 6,840.0 | 5,600.0 | 12,440.0 |
| Site preparation and utilities,[c] 20% of BLP | 1,210.0 | 1,080.0 | 2,290 | 1,470.0 | 980.0 | 2,450.0 | 1,370.0 | 1,120.0 | 2,490.0 |
| Fixed capital investment (FCI) | 7,280.0 | 6,480.0 | 13,760.0 | 8,800.0 | 5,880.0 | 14,680.0 | 8,210.0 | 6,720.0 | 14,930 |
| Working capital,[d] 20% of gross operating cost | 213.3 | 181.8 | 395.1 | 262.7 | 195.9 | 458.6 | 217.4 | 170.9 | 388.3 |
| Total capital investment | 7,493.3 | 6,661.8 | 14,155.1 (13,487.3) | 9,062.7 | 6,075.9 | 15,138.6 | 8,427.4 | 6,890.9 | 15,318.3 |
| **Annual operating cost** | | | | | | | | | |
| Labor[e] | 185.2 | 173.1 | 278.3 | 207.9 | 164.1 | 372.0 | 199.1 | 176.7 | 375.8 |
| Administrative and general overhead,[d] 60% of labor | 111.1 | 103.9 | 215.0 | 41.6 | 98.5 | 140.1 | 119.5 | 106.0 | 225.5 |
| Utilities[e] | 216.0 | 186.2 | 402.2 | 591.0 | 396.4 | 987.4 | 423.5 | 289.7 | 713.2 |
| Materials[e] | 437.5 | 270.9 | 708.4 | 235.2 | 161.8 | 397.0 | 123.2 | 100.8 | 224.0 |
| Local taxes and insurance,[d] 2.7% of FCI | 196.6 | 175.0 | 371.6 | 237.6 | 158.8 | 396.4 | 221.7 | 181.4 | 403.1 |
| Gross operating cost | 1,066.4 | 909.1 | 1,975.5 | 1,313.3 | 979.6 | 2,292.9 | 1,087.0 | 854.6 | 1,941.6 |
| Sulfur by-product credit,[f] $40/ton | - 165.9 | -95.4 | - 261.3 | - 165.9 | -95.4 | - 261.3 | - 165.9 | -95.4 | - 261.3 |
| Net operating cost | 900.5 | 813.7 | 1,714.2 | 1,147.4 | 884.2 | 2,031.6 | 921.1 | 759.2 | 1,680.3 |
| **Annualized cost** | | | | | | | | | |
| Annualized capital cost[g] | 763.2 | 678.5 | 1,441.7 (1,373.6)[b] | 923.0 | 618.8 | 1,541.8 | 858.3 | 701.9 | 1,560.2 |
| Federal income tax[d,h] | 133.4 | 118.5 | 251.9 (240.3)[b] | 161.4 | 108.6 | 270.0 | 149.6 | 122.2 | 271.8 |
| Net operating cost | 900.5 | 813.7 | 1,714.2 | 1,147.4 | 884.2 | 2,031.6 | 921.1 | 759.2 | 1,680.3 |
| Average annual cost | 1,791.1 | 1,610.7 | 3,407.8 | 2,231.8 | 1,611.6 | 3,843.4 | 1,929.0 | 1,583.3 | 3,512.3 |
| Average annual control cost, $/lb S removed | 0.194 | 0.302 | 0.233 (0.228) | 0.240 | 0.302 | 0.261 | 0.208 | 0.296 | 0.240 |

[a] Based on vendor estimates, December 1975. Each plant is independent, including sulfur recovery. Plant No. 1 is designed to clean 46 x $10^6$ scfd and Plant No. 2 is designed to clean 33 x $10^6$ scfd.

[b] Wilputte Corporation offered a reduced price if a contract was awarded to provide both facilities simultaneously.

[c] Site preparation, utility connections to battery limit plant, and COG connection to battery limit plant based on GCA review of similar costs reported in the literature.

[d] Based on Utility Financing Method as modified by the Panhandle Eastern Pipeline Company and described in Reference 42.

[e] See Tables 16 and 17.

[f] Conservative estimate based on price of $44/long ton received by SOHIO for by-product sulfur.

[g] Capital costs are amortized based on a discounted cash flow of 8 percent over 20 years.

[h] Average federal income tax = 1.731 percent of sum of total capital requirement and working capital.

plant.* Site preparation utility connection costs, and costs to tie the desulfurization facility into the by-product coke plants were estimated to be 20 percent of the installed battery limits plant. The total capital investment also includes the required working capital to cover daily operating costs. Working capital was estimated to be 20 percent of the gross annual operating cost. The capital investment for the battery limits plants were $11.5 million for the Holmes-Stretford system, $12.2 million for the Sulfiban system, and 12.4 million for the Dravo-Still system. Wilputte offered a 6 percent price reduction for their Holmes-Stretford system if a construction contract was awarded for both plants simultaneously. The total capital requirement for the Holmes-Stretford facility was $14,155,000. The Sulfiban and Dravo-Still System were slightly higher at $15,139,000 and $15,318,000, respectively.

Total annual operating costs, including credit for by-product sulfur, were lowest for the Dravo-Still system at $1,680,000. The Stretford system cost $1,714,000 per year to operate and the Sulfiban system cost $2,032,000 per year.

The total capital investment is amortized based on a discounted cash flow rate of 8 percent over 20 years to determine the annualized capital cost. Federal taxes and annual operating charges were added to the annualized capital charge to obtain the average annual cost. The annualized cost of the Holmes-Stretford system was lowest at $3.41 million, followed closely by the Dravo-Still facility at $3.51 million and the Sulfiban plants at $3.84 million. The sulfur control cost for all three systems was also close, ranging from $0.23 to $0.26/lb sulfur removed.

Alternative system designs are available that may require smaller capital outlays or provide reduced annual costs. For instance, BS&B suggested a

*Costs for the 65 x $10^6$ scfd systems are presented in the appendix.

10 to 15 percent less expensive battery-limits system which would consist of two Sulfiban plants with a common cyanide destruct plant and a common Claus sulfur recovery unit. The cyanide destruct and Claus units are highly reliable, so availability should approach 100 percent except for scheduled maintenance. BS&B also offered a system which would consist of one complete Sulfiban unit including sulfur recovery at the No. 1 Coke Plant, with a monoethanolamine scrubber at the No. 2 Coke Plant. In this case, sulfide-rich solution would be pumped from the No. 2 Plant to the Sulfiban system for stripping and clean solution returned to the No. 2 Plant scrubber.

Republic Steel expressed interest in producing a sulfuric acid by-product instead of elemental sulfur. This is easily done with the liquid absorption processes (Sulfiban, Dravo-Still) by replacing the Claus plant with a sulfuric acid plant. Dravo estimated that the capital costs of a battery-limits desulfurization system for production of 60° Be' sulfuric acid (77.67 percent acid) and including a tail-gas treatment system would be about $1,000,000 more than required for sulfur recovery. A similar increase in capital investment is necessary for sulfuric acid production capability in the Sulfiban system.

This acid could be used in the steel plant for pickling or in the coke by-products plant for ammonium sulfate production. Current value of 60° Be′ acid ranges from $35 to $43 per ton although demand is low compared to 66° Be′ acid (93 percent) or 100 percent acid. Most steel companies prefer 66° Be′ acid because of easier handling characteristics and a lower freezing point so that carbon steel pipes with no insulation or heater tracing can be used. The net operating and the annualized costs of COG desulfurization employing a sulfuric acid plant instead of a Claus plant may be lower.

## COST OF $SO_2$ CONTROL FOR BOILER D

### Flue Gas Desulfurization Boiler D

The design performance requirements for Boiler D $SO_2$ control are presented in Table 19. Coal combustion only (Case II) will only be approached when a blast furnace is shut down as occurred in 1974 and 95 percent of the fuel was coal. Shut down of a blast furnace is an extremely unusual situation. Cost estimates for flue gas desulfurization were based on data submitted by Research-Cottrell for a Bahco lime scrubbing system applied to a similar boiler but sized to handle 30,000 scfm.[4] Published literature[42] indicates similar costs for an FMC double alkali system but estimates could not be obtained within the time frame of this study. In addition FMC may not be willing to manufacture a system as small as 20,000 scfm although they do make a 33,000 scfm system.

Table 19. BOILER D DESIGN CONDITIONS FOR FLUE GAS DESULFURIZATION

| Desulfurization[a] | Case I Normal operation | Case II Coal combustion only |
|---|---|---|
| Rated capacity, $10^6$ Btu/hr | 461 | 461 |
| Annual load factor, percent | 80 | 80 |
| Flue gas volume, scfm | 95,000 | 95,000 |
| Heat input from coal percent | 81 | 100 |
| $SO_2$ emission rate, lb/$10^6$ Btu | 2.74 | 3.32 |
| Allowable $SO_2$ emission rate, lb/$10^6$ Btu | 2.22 | 2.22 |
| Emission reduction required, percent | 19 | 33 |
| Flue gas volume treated,[b] scfm | 20,000 | 35,000 |

[a] See Section II and Table 5 for further discussion.

[b] Volume treated at 90 percent effeciency to achieve the required emission reduction.

Utility, Material, and Labor Requirement and Cost - Table 20 presents the requirements for utilities, materials and labor for a flue gas desulfurization system applied to boiler D. Electric power requirements were based on data provided by Research-Cottrell and the assumption that for the range of conditions involved, power requirements were directly related to volumetric gas flow. Research-Cottrell reported that 0.25 men/shift could operate the system[46] but GCA used a more conservative estimate of 0.5 men/shift. In a recent study, Battelle also estimated 0.5 men/shift.[42] Estimates for maintenance material and labor were based on a TVA study of utility flue gas desulfurization systems.[47] Maintenance requirements used by GCA in Table 20 are more than twice as high as the 3 percent reported by Research-Cottrell[46] and Battelle[42] and should be considered as probable upper limits.

Costs of utility, material and labor are presented in Table 21. Process water specifications are not stringent and it may be possible to use a plant waste water stream. The total cost of utilities, materials and labor for normal operations which would involve a 20,000 scfm system are $191,500/year.

Capital and Annualized Costs - The capital costs of a installed battery limits plant (BLP) to desulfurizing flue gas from boiler D were based on an estimate by Research-Cottrell for a similar 30,000 scfm system. These costs are presented in Table 22. Capital costs of the 20,000 and 35,000 scfm were derived assuming the cost is a function of the system size to the 0.6 power, a common chemical engineering practice. This extrapolation is very reasonable for the small size range involved. Battery limit plant capital cost of a Bahco system for normal boiler D operations (Case 1) was estimated to $1 million.

Table 20. UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR THE FLUE GAS DESULFURIZATION APPLIED TO BOILER D AT MAXIMUM CAPACITY

| | Lime scrubbing, Bahco system by Research-Cottrell | |
|---|---|---|
| | Case 1 normal operation[a] | Case 2 coal combustion only |
| **Utility** | | |
| Power,[c] kWh/day | 3013 | 5270 |
| Steam, 1000 lb/day | 0 | 0 |
| Process water,[c] 1000 gal/day | 55 | 96 |
| **Material** | | |
| Lime, ton/day | 2.64 | 5.58 |
| Maintenance, percent of fixed capital investment per year | 3.5 | 3.5 |
| **Labor** | | |
| Operation, men/shift | 0.5 | 0.5 |
| Maintenance, percent of fixed capital investment per year | 3.5 | 3.5 |

[a]See Table 19. A 19 percent $SO_2$ emission reduction would be accomplished by cleaning 21 percent of the flue gas (20,000 scfm) at a 90 percent $SO_2$ collection efficiency.

[b]See Table 19. A 33 percent $SO_2$ emission reduction would be accomplished by cleaning 37 percent of the flue gas (35,000 scfm) at a 90 percent $SO_2$ collection efficiency.

[c]Based on vendor estimates for a similar system designed to clean 30,000 scfm of flue gas at a 90 percent $SO_2$ collection efficiency.

Table 21. UTILITY, MATERIAL, AND LABOR COSTS FOR FLUE GAS DESULFURIZATION APPLIED TO BOILER D BASED ON AN 80 PERCENT YEARLY LOAD FACTOR, $10^3$/YEAR, JUNE 1976

| | Lime scrubbing, Bahco system by Research-Cottrell | |
|---|---|---|
| | Case 1 Normal operation[a] | Case 2 coal combustion only |
| **Utility** | | |
| Power, $0.02/kWh[b] | 17.6 | 30.8 |
| Process water, $0.20/1000 gal | 4.0 | 5.6 |
| Total utilities | 21.6 | 36.4 |
| **Material** | | |
| Lime, $40/ton | 38.5 | 65.2 |
| Maintenance | 48.2 | 67.6 |
| Total materials | 86.7 | 132.8 |
| **Labor** | | |
| Operation, $8/man-hour | 35.0 | 35.0 |
| Maintenance | 48.2 | 67.6 |
| Total labor | 83.2 | 102.6 |
| Total utilities, material, and labor | 191.5 | 271.8 |

[a]Case 1 and Case 2 are defined in Table 19 and utility, material, and labor requirements are defined in Table 20.

[b]Ohio Edison.

Site preparation, cost to bring utilities to the battery limit plant and normal connection to flue gas duct was estimated to be 20 percent of the BLP cost. An additional retrofit cost equal to 15 percent of the BLP cost was included due to the site and boiler configurations based on data published by Devitt et al.[49] The derivation of other cost components are described in Table 22.

The average annual cost for flue gas desulfurization applied to boiler D to meet the proposed regulation is $462,000 which includes materials, labor, utility, capital changes, depreciation taxes, and solid waste disposal. $SO_2$ emissions would be reduced by 840 ton/year. This annualized control cost is equivalent to $0.275/lb sulfur collected or $0.177/$10^6$ Btu coal burned. For a coal with a heating value of 11,500 Btu/lb the annual control cost would be equivalent to $4.1 per ton of coal burned.

Low Sulfur Coal

As an alternative to flue gas desulfurization, compliance with the proposed regulation could be achieved by burning a lower sulfur coal. The present coal has an average sulfur content of about 2 percent and a heating value of 11,500 Btu/lb. During years of normal operation, Case I, a coal with 1.62 percent sulfur would comply with the proposed regulation and if only coal were burned a 1.34 percent sulfur content would be required. RSC indicated that changing from 2 percent sulfur coal to 1 percent sulfur coal would result in additional fuel costs of $12/ton. Presently 2 percent sulfur coal is obtained by spot purchases at various prices that RSC declined to specify. RSC provided to GCA coal data for the first 4 months of 1976 indicating that the January sulfur content was 1.48 percent, and the April sulfur content was 1.72 percent but during February and March sulfur content was above 2 percent. Because some of the coal used by RSC would comply with the proposed regulation, it may be possible for RSC to continuously burn compliance coal at a minimal cost.

Table 22. CAPITAL AND ANNUAL COSTS FOR FLUE GAS DESULFURIZATION APPLIED TO BOILER D BASED ON 80 PERCENT LOAD, $10^3$, JUNE 1976

| | Lime scrubbing, Bahco system by Research-Cottrell | |
|---|---|---|
| | Case 1 Normal operation[a] | Case 2 coal combustion only |
| **Capital requirement** | | |
| Battery limits plant installed (BLP)[b] | 1020 | 1430 |
| Site preparations and utilities,[c] 20% of BLP | 204 | 286 |
| Additional retrofit requirements,[d] 15% of BLP | 153 | 215 |
| Fixed capital investment | 1377 | 1931 |
| Working capital investment,[e] 20% of gross operating cost | 59 | 88 |
| Total capital investment | 1436 | 2019 |
| **Annual operating cost** | | |
| Labor[f] | 84 | 103 |
| Administration and general overhead,[e] 60% of labor | 52 | 80 |
| Utilities[f] | 22 | 36 |
| Materials[f] | 87 | 133 |
| Local taxes | 37 | 52 |
| Solid waste disposal, $4/ton | 14 | 35 |
| Gross operating cost | 296 | 439 |
| By-product credit | 0 | 0 |
| Net operating cost | 296 | 439 |
| **Annualized cost** | | |
| Annualized capital cost[g] | 140 | 206 |
| Federal income tax[e,h] | 26 | 36 |
| Net operating cost | 296 | 439 |
| Average annual cost | 462 | 681 |
| Average annual control cost | | |
| $/lbs [illegible]oved | 0.275 | 0.192 |
| $/10^6 Btu coal burned | 0.177 | 0.211 |

[a] See Table 19.

[b] Based on a vendor estimate of 1,300,000 for a similar 30,000 scfm system.[46]

[c] Normal site preparation; cost to bring utilities to the battery limit plant and connect raw flue gas ducts to BLP based on GCA review of similar costs reported in literature.

[d] Additional retrofit costs at Republic Steel due to site and boiler configuration.

[e] Based on utility financing method as modified by the Panhandle Eastern Pipeline Company and described in Reference 42.

[f] See Table 21.

[g] Total capital requirement is amortized over 20 years at a discount cash flow rate of 8 percent. This works out to an effective rate of 10.185 percent per year of the total capital requirement.

[h] Average Federal income tax = 1.731 percent of the sum of the total capital requirement and working capital.

Compliance coal is currently available from the Island Creek Coal Company.[50] This coal would cost $26 to $30 per ton delivered to Cleveland from West Virginia and Eastern Kentucky.[50] Spot purchases of compliance coal may be less costly at the present time.

RSC is probably paying $22 to $28 per ton for their present coal and therefore burning compliance coal may be less costly than flue gas desulfurization ranging from $0.0 to $0.3/$10^6$ Btu.

## SECTION V

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# APPENDIX A

## COST ESTIMATES FOR TWO COG DESULFURIZATION PLANTS TO CLEAN $65 \times 10^6$ scfd and $33 \times 10^6$ scfd

Table A-1. UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR COG DESULFURIZATION SYSTEMS AT REPUBLIC STEEL - CLEVELAND WORKS TOTAL CAPACITY, 98 x $10^6$ scfd[a]

| | Holmes-Stretford | | | Sulfiban | | | Dravo-Still | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total |
| **Utility** | | | | | | | | | |
| Power, kWh/day | 30,720 | 18,120 | 48,840 | 13,200 | 8,880 | 22,080 | 22,000 | 13,300 | 35,300 |
| Steam, 1000 lb/day | 79.2 | 52.8 | 132.0 | 700.0 | 308.0 | 1,008.0 | 587 | 260 | 847 |
| Coke oven gas, $10^6$ scfd | 0.24 | 0.168 | 0.408 | 0.4872 | 0.2712 | 0.7584 | 0.076 | 0.031 | 0.107 |
| Water, 1000 gal/day | | | b | 7,488 | 3,744 | 11,232 | | | b |
| **Materials** | | | | | | | | | |
| Vanadium, lb/day | 3 | 1 | 4 | - | - | - | - | - | - |
| Anthraquinone disulfonic acid, lb/day | 185 | 70 | 255 | - | - | - | - | - | - |
| Anhydrous citric acid, lb/day | 540 | 200 | 740 | - | - | - | - | - | - |
| Monoethanolamine, lb/day | - | - | - | 972 | 493 | 1,465 | - | - | - |
| E-437 inhibitor (Tretalite), gal/day | - | - | - | 2 | 1 | 3 | - | - | - |
| Maintenance, percent of fixed capital investment/yr[c] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| **Labor** | | | | | | | | | |
| Operator, men/shift | 1 | 1 | 2 | 1 | 1 | 2 | 1 | 1 | 2 |
| Chemist,[4] hr/day | 2 | 2 | 4 | 2 | 2 | 4 | 2 | 2 | 4 |
| Maintenance, percent of fixed capital investment/yr[c] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |

[a] Based on vendor estimates, December 1975. Plant No. 1 would clean 65 x $10^6$ scfd and plant No. 2 would clean 33 x $10^6$ scfd.

[b] Not significant, cooling towers included in capital and operating costs. Electric power consumption for cooling operation is approximately 35 percent of total.

[c] GCA assumption, similar to estimates used by Massey[9,13] and Choi, et al.[42] for industrial pollution control processes.

## Table A-2. UTILITY, MATERIAL, AND LABOR COSTS FOR COG DESULFURIZATION SYSTEMS AT REPUBLIC STEEL - CLEVELAND WORKS TOTAL CAPACITY, 98 x 10$^6$ scfd $/DAY[a]

| | Holmes-Stretford | | | Sulfiban | | | Dravo-Still | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total |
| **Utility** | | | | | | | | | |
| Electric power, $0.02/kWh[b] | 614.4 | 362.4 | 976.8 | 264.0 | 177.6 | 441.6 | 440.0 | 266.0 | 706.0 |
| Steam, $2/1000 lb[c] | 158.4 | 105.6 | 264.0 | 1,400.0 | 616.0 | 2,016.0 | 1,174.0 | 520.0 | 1,694.0 |
| Coke oven gas, $250/10$^6$ scf[d] | 60.0 | 42.0 | 102.0 | 121.8 | 67.8 | 189.6 | 19.0 | 7.8 | 26.8 |
| Cooling water, $0.06/1000 gal[e] | - | - | - | 449.3 | 244.6 | 673.9 | - | - | - |
| Total utilities | 832.8 | 510.0 | 1,342.8 | 2,235.1 | 1,086.0 | 3,321.1 | 1,633.0 | 793.8 | 2,426.8 |
| **Material** | | | | | | | | | |
| Vanadium, $5/lb[f] | 15.0 | 5.0 | 20.0 | - | - | - | - | - | - |
| Anthraquinone disulfonic acid, $5.3/lb[f] | 980.5 | 371.0 | 1,351.5 | - | - | - | - | - | - |
| Anhydrous citric acid, $0.5/lb[f] | 270.0 | 100.0 | 370.0 | - | - | - | - | - | - |
| Monoethanolamine, $0.4/lb[g] | - | - | - | 388.8 | 197.2 | 586.0 | - | - | - |
| K-437 inhibitor (Tretalite), $4.5/lb[h] | - | - | - | 9.0 | 4.5 | 13.5 | - | - | - |
| Maintenance, 1.5 percent of fixed capital investment/yr | 367.4 | 266.3 | 633.7 | 443.8 | 241.6 | 685.4 | 414.2 | 276.2 | 690.4 |
| Total material | 1,632.9 | 742.3 | 2,375.2 | 841.6 | 443.3 | 1,284.9 | 414.2 | 276.2 | 690.4 |
| **Labor** | | | | | | | | | |
| Operator, $8/hr | 192.0 | 192.0 | 384.0 | 192.0 | 192.0 | 384.0 | 192.0 | 192.0 | 384.0 |
| Chemist, $8/hr | 16.0 | 16.0 | 32.0 | 16.0 | 16.0 | 32.0 | 16.0 | 16.0 | 32.0 |
| Maintenance, equal to maintenance material | 367.4 | 266.3 | 633.7 | 443.8 | 241.6 | 685.4 | 414.2 | 276.2 | 690.4 |
| Total labor | 575.4 | 474.3 | 1,049.7 | 651.8 | 449.6 | 1,101.4 | 622.2 | 484.2 | 1,106.4 |
| Total daily operating cost | 3,041.1 | 1,726.6 | 4,767.7 | 3,728.5 | 1,978.9 | 5,707.4 | 2,669.4 | 1,554.2 | 4,223.6 |

[a] See Table A-1 for utility, material, and labor requirements.

[b] Ohio Edison.

[c] Based on electricity cost and 10 lb steam/kWh.

[d] Based on $0.5/10$^6$ Btu and a heating value of 500 Btu/scf.

[e] Massey.[9] If cooling tower is included in system, cost of make-up water is assumed to be negligible.

[f] Wilputte Corporation.

[g] Chemical Marketing Reporter, May 1976.

[h] BS&B, Process System Division.

Table A-3. COSTS FOR COG DESULFURIZATION SYSTEMS AT REPUBLIC STEEL - CLEVELAND WORKS TOTAL CAPACITY, 98 x $10^6$ scfd, $10^3$

| | Holmes-Stretford | | | Sulfiban | | | Davo-Still | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total | Plant No. 1 | Plant No. 2 | Total |
| **Capital requirement** | | | | | | | | | |
| Battery limits plant, installed (BLP)[a] | 7,450.0 | 5,400.0 | 12,850.0 (12,100.0)[b] | 9,000.0 | 4,900.0 | 13,900.0 | 8,400.0 | 5.600.0 | 14,000.0 |
| Site preparation and utilities,[c] 20% of BLP | 1,490.0 | 1,080.0 | 2,570.0 | 1,800.0 | 980.0 | 2,780.0 | 1,680.0 | 1,120.0 | 2,800.0 |
| Fixed capital investment (FCI) | 8,940.0 | 6,480.0 | 15,420.0 | 10,800.0 | 5,880.0 | 16,680.0 | 10,080.0 | 6,720.0 | 16,800.0 |
| Working capital,[d] 20% of gross operating cost | 295.0 | 181.8 | 477.3 | 359.0 | 195.9 | 554.5 | 276.6 | 170.9 | 381.7 |
| Total capital investment | 9,235.0 | 6,661.8 | 15,897.3 (15,147.3)[b] | 11,159.0 | 6,075.9 | 17,234,9 | 10,356.6 | 6,890.9 | 17,181.7 |
| **Annual operating cost** | | | | | | | | | |
| Labor[e] | 210.0 | 173.1 | 383.1 | 237.9 | 164.1 | 402.0 | 227.1 | 176.7 | 403.8 |
| Administrative and general overhead,[d] 60% of labor | 126.0 | 103.9 | 229.9 | 142.7 | 98.5 | 241.2 | 136.3 | 106.0 | 242.3 |
| Utilities[e] | 304.0 | 186.2 | 490.1 | 815.8 | 396.4 | 1,212.2 | 596.0 | 289.7 | 885.8 |
| Materials[e] | 596.0 | 270.9 | 866.9 | 307.2 | 161.8 | 469.0 | 151.2 | 100.8 | 252.0 |
| Local taxes and insurance,[d] 2.7% of FCI | 241.4 | 175.0 | 416.3 | 291.6 | 158.8 | 450.4 | 272.2 | 181.4 | 453.6 |
| Gross operating cost | 1,477.4 | 909.1 | 2,386.5 | 1,795.2 | 979.6 | 2,774.8 | 1,382.8 | 854.6 | 2,237.4 |
| Sulfur by-product credit,[f] $40/ton | - 233.4 | - 95.4 | - 328.8 | - 233.4 | - 95.4 | - 328.8 | - 233.4 | - 95.4 | 328.8 |
| Net operating cost | 1,244.0 | 813.7 | 2,057.7 | 1,561.8 | 884.2 | 2,446.0 | 1,149.4 | 759.2 | 1,908.6 |
| **Annualized cost** | | | | | | | | | |
| Annualized capital cost[g] | 940.7 | 678.5 | 1,619.2 (1,542.8)[b] | 1,136.6 | 618.8 | 1,755.4 | 1,054.8 | 701.9 | 1,750.0 |
| Federal income tax[d,h] | 165.0 | 118.5 | 283.4 (270.5)[b] | 199.4 | 108.6 | 308.0 | 184.1 | 122.2 | 303.8 |
| Net operating cost | 1,244.0 | 813.7 | 2,057.7 | 1,561.8 | 884.2 | 2,446.0 | 1,149.4 | 759.2 | 1,908.6 |
| Average annual cost | 2,349.7 | 1,610.7 | 3,960.3 (3,871.0) | 2,897.8 | 1,611.6 | 4,509.4 | 2,388.3 | 1,583.3 | 3,962.4 |
| Average annual control cost, $/lb S removed | 0.180 | 0.302 | 0.215 (0.210) | 0.222 | 0.302 | 0.245 | 0.183 | 0.296 | 0.215 |

[a] Vendor estimates, December 1975. Each plant is independent, including sulfur recovery. Plant No. 1 would clean 65 x $10^6$ scfd and plant No. 2 would clean 33 x $10^6$ scfd.

[b] Wilputte Corporation offered a reduced price if a contract was awarded to provide both facilities simultaneously.

[c] Site preparation, utility connections to battery limit plant, and COG connection to battery limit plant based on GCA review of similar costs reported in the literature.

[d] Based on Utility Financing Method as modified by the Panhandle Eastern Pipeline Company and described in Reference 42.

[e] See Tables A-1 and A-2.

[f] Conservative estimate based on price of $44/long ton received by SOHIO for by-product sulfur.

[g] Capital costs are amortized based on a discounted cash flow of 8 percent over 20 years.

[h] Average federal income tax = 1.731 percent of sum of total capital requirement and working capital